CALIFORNIA ENERGY COMMISSION

Making Better Connections:

Cost Effectiveness Report on Interconnection of Distributed Generation in California Under the Revised Rule 21

CONSULTANT REPORT

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Arnold Schwarzenegger, *Governor*

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PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings End-Use Energy Efficiency
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Environmentally Preferred Advanced Generation
- Energy-Related Environmental Research
- Energy Systems Integration

What follows is the final report for Contract #500-00-013, conducted by Reflective Energies and Overdomain, LLC. The report is entitled "Making Better Connections: Cost Effectiveness Report on Interconnection of Distributed Generation in California Under the Revised Rule 21". This project contributes to the Energy Systems Integration.

For more information on the PIER Program, please visit the Energy Commission's Web site at: http://energy.ca.gov/research/index.html or contact the Energy Commission's Publications Unit at 916-654-5200.

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EXECUTIVE SUMMARY

The California Energy Commission, with support from the FOCUS[1] team (Reflective Energies, Prime Contractor; Overdomain, LLC and Endecon Engineering, Subcontractors), has taken a leadership role in developing revised, streamlined requirements for interconnection of electric power generators to the California electricity distribution system. The California Energy Commission orchestrated the revisions by a consensus-building process through a Rule 21 Working Group, an open forum comprised of utilities, Distributed Generation (DG) developers, equipment manufacturers, consultants, industrial commercial and residential DG users. The Working Group has continued to meet about ten times each year to consider further improvements to Rule 21 and related issues. The revised Rule 21 provides for certification of systems that are grid-interactive. It has a simplified interconnection approval process for generators that have a low impact on the grid, and provides for step-wise increases in fees and analysis as the impact increases.

The process of working together to revise Rule 21 has increased all stakeholders' understanding of DG systems and how they may be integrated into the distribution system. Communications with the utilities have improved considerably, and interconnections are now proceeding more rapidly and smoothly.

This FOCUS study examines data relative to the interconnection progress in California and takes an objective look at how the Revised Rule 21 has impacted interconnections; as a baseline the study used a prior report by NREL, titled "Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects" ("MC"). The NREL Report used case studies, rather than an analysis of all data, and obtained information by interviewing developers. The NREL study did not include any discussion with utilities. Nevertheless, it provided valuable insight on the problems faced by DG developers and the delays and obstacles they faced. It also listed the barriers that needed to be overcome, and is a credible baseline for measuring progress.

The FOCUS study analyzed the factual data from all interconnection applications to the three major Investor Owned Utilities (IOUs) in California for 2001, 2002 and 2003. The data is collected each month by each IOU and provided to the CEC and the Working Group. Reasonable assumptions are made to convert the data into costs.

The Revised Rule 21 has resulted in dramatic reduction in the speed and costs of most interconnections. The average time from application to interconnection has dropped, on average, from over one year to less than three months, and is dropping even more. In most cases, the fees associated with interconnection have also dropped (from about $5,000 or more to $800 or $1,400 per application). When all costs savings are considered, the overall benefit to developers is estimated to be about $8,000,000 in 2001, $10,000,000 in 2002, and $15,000,000 in 2003. These savings are anticipated to grow each year as DG proliferates. This benefit compares very favorably with the costs incurred by the Energy Commission, estimated to be

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[1] FOrging a Consensus on Utility System Interconnection

about $750,000 per year for the last three years. Compared to MC, a DG developer's relative interconnection cost overruns for units less than 1MW have reduced by 50% to 75%.

The Revised Rule 21 has been adopted by several major municipal utilities in California, and has become a model for utilities in other states and other countries. Rule 21 is already fairly compatible with the new IEEE standard for interconnection of DG adopted in 2003; the Working Group is taking steps to make it fully compatible.

Perhaps more important than the improvements in costs and schedules, the relationships between developers and utilities has also improved. As stated in the NREL Report, many developers believed that some utilities use unreasonable terms, excessive costs and inappropriate delays to either gain advantage or impede the market. However, today the overall atmosphere in California is much more cooperative. Utilities have begun to hold seminars for potential DG customers, have adopted "single points of contact", are training their own people in DG review processes and have been striving to improve their interconnection timeline scorecards.

More needs to be done, but the efforts so far have been highly successful.

1.0 Introduction

The purpose of this study is to assess the cost effectiveness of the work being performed by the California Energy Commission to improve the process of interconnecting Distributed Generation in California to the electric distribution system. This study is part of the Energy Commission's PIER contract 500-00-013, also known as "FOCUS-II". The term "cost effectiveness" is used in this paper to refer to progress toward the specific objectives of the Focus II contract: the Process Improvement Objective, the Simplified Interconnection Objective, the Time Reduction Objective, and the Cost Reduction Objective. (See Section 1.1 below.) Progress toward these Objectives, to the extent it could be ascertained from the data at hand, is treated here as the basis for determining cost effectiveness, that is, the effectiveness of dollars spent fulfilling these interconnection objectives. The benefit measured is taken from the perspective of project developers, who are often also utility customers.

Electric utilities traditionally generated, transmitted and distributed their own power using large power plants within their franchise territories. The interconnection of these power plants was an internal process between the utility generation and transmission departments. With the advent of the Public Utilities Regulatory Policy Act of 1978 (PURPA), utilities were required to allow interconnection and to purchase power from "Qualifying Facilities" or "QFs". In California these interconnections were performed under Public Utilities Commission approved tariff Rule No. 21, or simply, "Rule 21". These PURPA power plants, owned by Independent Power Producers, or "IPPs", were also mostly large power plants, from 10 megawatts to hundreds of megawatts capacity. Rule 21 was cumbersome to comply with, but interconnection of relatively large power plants has serious reliability and safety implications for the grid. These plants were usually interconnected to the utility transmission system, most commonly at a substation and at high voltages (11 kV or greater), but smaller capacities at distribution system voltages. Often, the cost of the interconnection, while expensive, was not overwhelming when compared to the cost of the overall power plant.

With the advent of renewable energy and other technological developments, small power plants such as photovoltaic solar power ("PV"), microturbines and clean internal combustion engines became more widespread and feasible for self-generation. These power plants are connected on the customer side of the electric meter, and therefore connected to the low voltage side of the utility distribution system. At that time, Rule 21 was not well suited to address such small power plants. Large subsidies and public policy made small PV power plants popular. However, the interconnection of these plants could be as expensive as the power plant itself. To remedy this problem, the PV community helped forge legislation and regulations in California and elsewhere to simplify the interconnection of very small net energy metered systems (below 10 kW) at low voltages to the distribution system. However, the interconnection of plants larger than 10 kW and too small to absorb the high cost of interconnection remained a major problem. The California Public Utilities Commission requested the assistance of the California Energy Commission to author a revised model Rule 21 tariff by organizing a Working Group with all the stakeholders in DG working together in a consensus. The intent was to reduce the cost and time to interconnect DG without compromising the safety and reliability of the distribution system.

The three largest investor-owned utilities (IOUs) in the state—Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)—each had its own version of Rule 21 prior to this model rule. After one year of deliberations by the multi-stakeholder group, a model Rule 21 was completed, and adopted by the California Public Utilities Commission on December 21, 2000.[2] The questions explored in this study are: What effect has the Revised Rule 21 had on the cost-effectiveness of interconnection to the distribution system, compared to the old Rule 21? Have the Working Group's efforts been cost-effective considering an extended period of time into the future?

The Technical and Economic performance Objectives (see Section 1.1, Objectives, for details) set qualitative and quantitative benchmarks[3] for the performance improvements of the revised Rule 21. To gauge the progress achieved by this work, we compared performance before-and-after implementation of the revised Rule 21. The description for Task 2.3.2 indicates how the comparison should be performed, at least in part. It states:

The Contractor shall consolidate the participating utilities' monthly status sheets to the Interconnection Workgroup on new DG applications being processed under the Revised Rule 21[4] requirements. The Contractor shall track which applications qualify for Simplified Interconnection, Interconnection subject to additional requirements, or Interconnection Study to determine Interconnection Requirements. From this data and other means, the Contractor shall determine the cost-effectiveness of the Revised Rule 21 and prepare an analysis in attaining the economic objectives for this contract. The analysis should recommend specific areas in which the Rule 21 requirements can be further simplified in order to decrease the interconnection application and equipment costs. Key elements of this analysis shall be included in the final report.[5]

Comparing common features of interconnections under the old Rule 21 with those same features of interconnections after revisions to Rule 21 will gauge progress toward interconnection that is less costly and less time consuming. Meaningful comparison will require sufficient samples of projects, both before and after Rule 21 was first published in its revised form (12-21-2000).

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[2] The three utilities have subsequently filed additional advice letters updating Rule 21 to ensure consistency.

[3] Standard Agreement 500-00-013, Exhibit A, page 1.

[4] The contract text refers to the current Rule 21 as "Revised Rule 21", since it is "revised" from the old PURPA-era Rule 21. In this paper, the Revised Rule 21 is the basis of the Trendline (that is, the interconnection conditions existing after passage of the Revised Rule 21); the old Rule 21 is the condition underlying the Baseline.

[5] Standard Agreement 500-00-013, Exhibit A, page 6.

1.1. Objectives

The contract technical objectives that are the basis of the assessment are as follows:

1. Process Improvement Objective

   Evaluate whether Revised Rule 21 has improved the process of interconnection of DG to the electrical system;[6]

2. Simplified Interconnection Objective

   Assess the potential for simplifying Rule 21 further to expand the types of different applications eligible for a "Simplified Interconnection" and thus improve the cost-effectiveness of interconnection.

The economic objectives assessed in this Report are as follows:

3. Time Reduction Objective

   Reduce the average time associated with approval and installation of interconnection by more than 20 percent for projects less than 1 MW.

4. Cost Reduction Objective[7]

   Reduce the cost of interconnection below what was experienced prior to the Revised Rule 21 by 30 percent for units less than 1 MW and by 15 percent for units equal to or greater than 1 MW;

1.2. Progress Toward Objectives

Cost Effectiveness, in its meaning in this paper, is the degree to which Rule 21 meets the objectives of the FOCUS-II contract (see Section 1.1). Measuring cost effectiveness, that is, progress toward the objectives, requires construction of a "Baseline" of what would have happened absent revisions to Rule 21 and comparing that to a "Trendline" of what actually happened. Measurement is a four-step process:

1. Collect data for a Baseline made up of interconnection projects or requirements under conditions of the old Rule 21 or equivalent non-Rule 21 situations;

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[6] Interpreted to apply only to the distribution system.

[7] This study did not include a determination of interconnection costs, through customer surveys or other methods, either before or after the Revised Rule 21. Interconnection costs are very difficult to quantify, because it is not a simple matter to establish what would be part of the power plant and what has been added solely because of additional utility requirements. Data covering the period before the Revised Rule 21 was available on relative cost overruns—amounts, that is, that customers considered to be in excess of what they expected to pay.

2. Collect data for a Trendline made up of interconnection projects or requirements under conditions of the Revised Rule 21;

3. Compare the Trendline to the Baseline;

4. Compare results of Step #3 with the objective, to yield progress toward the objective.

Each objective has one or more Baseline data source and one or more Trendline data source. Comparison may result in qualitative or quantitative value. The following sections will cover the Baseline and Trendline data sources and methodologies for comparison for each objective.

1.2.1. Data Sources

It was not possible to obtain complete economic and technical data for each project in the Baseline and the Trendline because some of the data is proprietary and protected. A significant amount of data was, however, available, and does allow certain conclusions to be reached, but also leaves some gaps in the understanding of cost effectiveness.

Four data sources were used to determine cost effectiveness of California interconnections under Revised Rule 21:

1. A report titled "Making Connections" on pre-2001 interconnections from DOE[8] provided the baseline data;

2. Lists of distributed generation interconnections under Revised Rule 21 provided by PG&E, SCE and SDG&E to the California Energy Commission and the Rule 21 Working Group;

3. Details of the interconnection review process provided to the FOCUS team by the three major utilities: separation of interconnection applications into those approved through Initial Review, those approved through Supplemental Review and those approved following a Detailed Study;

4. The Revised Rule 21 itself.

Though on-site power generation is not new, DG is new as an emerging industry; there are few available studies of the costs of interconnection. It was decided to use for Baseline data the NREL[9]-sponsored report entitled "Making Connections"[10] data. Making Connections is a case study of 65 interconnections undertaken across the United States. This information was gathered from interviews with manufacturers, developers and owners of distributed generation projects. All major technologies, fuels, sizes and operating modes, were represented.

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[8] Department of Energy

[9] National Renewable Energy Laboratory

[10] Making Connections *Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects*, R.B. Aldefer, M. Eldridge, T. Starrs, May 2000.

Interconnection barriers are described in detail. Some of the Baseline data for this comparison comes from MC. Since most of these interconnections were made under different requirements than California's old Rule 21, an analysis is carried out to eliminate projects from the baseline not representative of those requirements.

MC does not disclose absolute cost or delay information. Instead, it is based on interviews with DG developers and presents relative costs and delays—that is, dollars and months over the customer's expected expenditure. The report does not claim to be balanced. It states, "…these cases primarily represent the developers views of what they encountered in seeking to interconnect these facilities. Therefore, the cases reported here may not reflect what might be a very different utility position with respect to some of the cases". Section 2.0 below contains a detailed description of what information is used from the NREL report and how it is applied to measure progress toward the objectives.

The second data source under the Revised Rule 21 for determining cost-effectiveness is the series of California Interconnection Status Reports ("CaIS Reports") provided monthly by each of the large California IOUs as a courtesy to the interconnection Working Group, at the request of the California Energy Commission.[11] This data is available to all stakeholders and consists of information gathered by each utility on interconnection activity in its own territory. It is therefore deemed to be accurate, usable both for both Baseline (applications prior to 12-21-2000) and Trendline (applications after 12-21-2000). CaIS Reports contain information on all distribution-level interconnections in the IOU territories—except Net Energy Metering (NEM) projects. Data have been collected monthly since April of 2001. Fields include: Customer Type, City, Total Gross kW, Technology, Interconnect Type, Operating Mode, Date Received, Requested On-line, Contract Execution, Authorized Interconnect Date, and Status. Time-to-interconnect is well documented and includes both absolute and relative delay information. No absolute or relative interconnection costs are disclosed.

The third data source was a summary listing provided by each of the California utilities at the request of the FOCUS group. While each utility provided the data in a different format, the information showed how utility review was conducted by each utility: which applications were approved following Initial Review, which others were approved following Supplemental Review, and which were approved following a formal Interconnection Study. The utility charges for these reviews were generally available, but the cost of performing the interconnection is a more complex matter, and those costs were not obtained.

The fourth data source for determining Cost Effectiveness is the Revised Rule 21 itself. Making Connections contains recommendations for reducing interconnection barriers. Where these recommendations serve as a relevant Baseline, they can be compared to Revised Rule 21 see to what extent they are fulfilled. Revised Rule 21 can also be compared against Baseline situations to see whether the improved requirements would cause reduced cost if applied.

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[11] Summaries of CaIS Reports may be found at:
http://www.energy.ca.gov/distgen/interconnection/rule21_stats.html

1.2.2. Cost Effectiveness Methodology

In order to measure progress toward achieving the objectives, we defined the Baseline, Trendline, and comparison result data type. Each objective below will begin with a description to give an idea of the overall methodology for measuring cost-effectiveness.

Process Improvement Objective

Description: The evaluation compares the Baseline interconnection process, as applied in particular Baseline projects, with the Revised Rule 21 interconnection process. An improved process is scored as a percentage of actual achievement against a standard of complete success (where success=100%, failure=0%).

Baseline data source: Making Connections

Trendline data source: Revised Rule 21

Result: Scored qualitative comparison

Simplified Interconnection Objective

Description: Document results of efforts to expand applications eligible for Simplified Interconnection[12]. Under Revised Rule 21, there are three tracks to interconnection: 1. Approval upon Initial Review resulting in Simplified Interconnection ; 2. Approval upon Supplemental Review either through Simplified Interconnection or with additional requirements; and 3. Approval following a Detailed Study, probably resulting in additional requirements. The first is usually the fastest and least expensive track; the third (Detailed Study) is usually the longest and costliest track. The Simplified Interconnection Objective aims to measure the number of projects taking the fast track. Expanded eligibility for Simplified Interconnection counts as qualitative (non-numerical) improvement in cost-effectiveness.

Baseline data source: Making Connections

Trendline data sources: 1. Revised Rule 21; 2. Special utility interconnection reports.

Result: Quantitative comparison of total projects passing on Initial Review (and Supplemental / Detailed Study) as a percentage of total interconnections;

Time Reduction Objective

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[12] According to Rule 21, Simplified Interconnection is "Interconnection conforming to the minimum requirements under this Rule, as determined by Section I." See Rule 21, Section I for details: http://www.energy.ca.gov/distgen/interconnection/california_requirements.html

Description: Compare Rule 21 time delays in approval with baseline time delays; if Revised Rule 21 reduces interconnection delay by 20% or more for units less than 1MW, the Time Reduction Objective will be met.

Baseline data source: Making Connections, CaIS Reports

Trendline data source: CaIS Reports

Result: Numerical comparison

Cost Reduction Objective

Description: Reconstruct Rule 21 Trendline cost data from MC projects, comparing them to Baseline MC cost data; if units smaller than 1MW are reduced in cost by at least 30% from the baseline, or 15% for units equal to or greater than 1MW, the Cost Reduction Objective will be met. Removal of technical and business barriers (as defined in MC) from baseline projects counts as qualitative improvement in cost-effectiveness, but will not be scored.

Baseline data source: Making Connections

Trendline data source: Engineering estimates of Revised Rule 21 costs of compliance

Result: Estimated numerical comparison

2.0 Cost Effectiveness Baselines

2.1. Baseline Methodology

NREL's "Making Connections" report is based on interviews conducted with developers of 65 distributed generation projects across the United States. Of these, 26 were selected as case studies and given detailed treatment. Twenty-five of the 65 projects gave figures on how much the cost to interconnect exceeded their expectations; thirty-nine of 65 gave figures on how much the time to interconnect exceeded their expectations. The report is useful to an assessment of Rule 21 cost effectiveness because it contains baseline information that relates to the four technical and economic objectives described in Section 1.2.2 above:

1. It provides an "Action Plan" useful in determining whether the Process Improvement Objective has been met;
2. It contains data for all case studies reporting time overruns, useful as a baseline of comparison for the Time Reduction Objective.
3. It contains data for all case studies reporting cost overruns, useful as a baseline of comparison for the Cost Reduction Objective; it contains descriptions of each case study, useful in assessing the applicability of Baseline costs to the Trendline.

Not all of these 65 projects contained in the NREL report can be used in the Baseline. Solar and wind generation projects equal to or smaller than 10 kW are eligible in California for Net Energy Metering (NEM)[13] and were not originally covered under Rule 21.[14] There is separate regulatory code[15] that describes how utilities are required to handle these projects. This paper will not include NEM less than or equal to 10kW because California law mandates that the costs associated with such projects must be borne by the utility.

Furthermore, projects in the NREL study delayed by issues that would be unlikely to exist in pre-Rule 21 California have been removed from the Baseline.[16] NREL study projects are also excluded from the baseline when the barrier to project operation is something other than

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[13] Net Energy Metering is the utility tariff that allows customers to install certain renewable energy generators (primarily photovoltaic and wind) and sell excess power back to the utility at the customer's retail rate. This is sometimes called "spinning the meter backwards", since the meter actually turns in reverse when the system is exporting power.

[14] California has an expanded Net Energy Metering program, covering renewable generation up to 1MW that was established in 2001, with sunset provisions extended in2003. IOU's perform Initial Review (and Supplemental Review, if necessary) on "expanded" NEM projects (11 - 1000kW). Efforts are currently under way to bring NEM projects into harmony with Rule 21, although some differences will remain. One of these differences is that the Utility's are required to absorb the cost of NEM interconnection study.

[15] Public Utilities Code, Section 2827.

[16] Such as the "steam subsidy" in MC Case #1 or the "Power for Jobs" tariff in Case #10.

interconnection (environmental regulations or standby rates, for example). When Net Energy Metered projects and projects with non-interconnection issues are eliminated, forty-one sites from the Making Connections report are left in the baseline: 6 inside California and 35 outside the state.

The time delay Baseline is supplemented here by CaIS projects in California that began the process of interconnection prior to December 21, 2000—the date that the CPUC[17] issued its decision to adopt Revised Rule 21. There are a total of twelve CaIS projects that fit this description, all from SCE and SDG&E. None of these projects went online prior to December 21, 2000—all went into service after that date. In consideration of how these projects were administered, however, their inclusion in the Baseline makes sense:

- They didn't use the Revised Rule 21 application form;
- They didn't go through Initial Review, as defined by the new Rule 21;
- They were not subject, therefore, to the time limits and constraints imposed by the new Rule 21;
- There was no such thing as Simplified Interconnection when they applied;
- There was no such thing as Certified Equipment when they applied (although the concept of Interim EC Approval may have been applied periodically);
- They were processed by the utility, at the time they were received, the same way baseline projects were processed;
- There is no provision under Revised Rule 21 that would reduce the time to review or the cost to implement interconnections that were already underway under the old Rule 21.

For these reasons, the 12 early CaIS projects are included in the Baseline. Appendix A shows a complete list of projects included in the Baseline.

2.2. Baseline for Process Improvement Objective

The Making Connections report offers a "Ten-Point Action Plan for Reducing Barriers to Distributed Generation".[18]

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[17] California Public Utilities Commission

[18] Making Connections, Executive Summary, p. iv.

Table 1 "MAKING CONNECTIONS" TEN-POINT ACTION PLAN

Reduce Technical Barriers

1. Adopt uniform technical standards for interconnecting distributed power to the grid.
2. Adopt testing and certification procedures for interconnection equipment.
3. Accelerate development of distributed power control technology and systems.

Reduce Business Practice Barriers

4. Adopt standard commercial practices for any required utility review of interconnection.
5. Establish standard business terms for interconnection agreements.
6. Develop tools for utilities to assess the value and impact of distributed power at any point on the grid.

Reduce Regulatory Barriers

7. Develop new regulatory principles compatible with distributed power choices in both competitive and utility markets.
8. Adopt regulatory tariffs and utility incentives to fit the new distributed power model.
9. Establish expedited dispute resolution processes for distributed generation project proposals.
10. Define the conditions necessary for a right to interconnect.

These ten points will be treated in this paper as baseline conditions that, if fulfilled by the new Rule 21, are considered evidence of qualitative fulfillment of the Process Improvement Objective. The rationale for this approach is that to the extent Rule 21 is making progress toward achieving one or more of these 10 points, it is making progress toward "[improving] the process of interconnection of DG to the electrical system", as required by the Process Improvement Objective.

Some of these points do not concern interconnection and should be modified or eliminated from consideration for our comparison:

- Point #3 recommends acceleration of control technology and is beyond the scope of this study;
- Point #7 recommends the formulation of new regulatory principles and will be narrowed to include interconnection only;
- Point #8, addresses regulatory tariffs and utility incentives, which are issues outside the scope of this study and will be narrowed to include interconnection only.

As an aside, the revised Rule 21 was among the first in the nation to adopt uniform standards for interconnecting distributed generation, to develop and adopt testing and certification procedures, to adopt standard application forms and review processes, and to develop utility tools to assess the impact of distributed power upon the grid, and, and the Working Group has helped towards many of the other recommendations. The Working Group has used the NREL Making Connections Report as a springboard from which to launch improvements in the processing and review of DG interconnections. This report assesses the cost and time impact of those improvements.

2.3. Baseline for Simplified Interconnection Objective

2.3.1. Baseline Interconnection Process

The Simplified Interconnection Objective baseline is simple to construct because the old Rule 21 did not provide for Simplified Interconnection.[19] All projects had to go through what is now called Detailed Study. Any interconnection made with less than a Detailed Study, therefore, represents progress toward the objective. Evidence for this progress is found in the Revised Rule 21. As shown in Section 3.2, the utilities have provided information on interconnections requiring Simplified, Supplemental and Detailed Study. To the extent that Revised Rule 21 provisions and Certification provide process improvement and opportunities for Simplified Interconnection or Supplemental Review (thereby avoiding a Detailed Study), they successfully fulfill the Simplified Interconnection Objective.

2.3.2. Overall Baseline Results

The 65 Baseline interconnection projects tracked in Making Connections produced the following results:

- 29 were completed and interconnected—no detail was given, but it is reasonable to assume they operate in parallel with the grid (on-site load with no export);
- 9 were interconnected and are explicitly operating in parallel with no export;
- 2 were disconnected from the grid, and it is unknown whether they are operating isolated from the grid or were shut down;
- 7 were installed (at time of writing of MC) but were not then interconnected, though perhaps operating isolated from the grid (i.e. not in parallel with the EC) in the interim;
- 13 were pending (at time of writing of MC);
- 5 were abandoned.

[19] A project qualified for Simplified Interconnection is one that is approved following only the Initial Review, and in some cases following the Supplemental Review, and does not require a Detailed Study.

2.4. Time Reduction Objective

2.4.1. Considerations in Constructing the Baseline

The Baseline for the Time Reduction Objective comes from these sources:

- The Making Connections report;
- The California DG lists (CaIS Reports), modified and prepared as described above in Section 2.1.

Both Making Connections and CaIS have time-related data, but they are each in a different format. Making Connections shows only relative time overruns, that is, months beyond expected completion date. The CaIS data tracks the actual date that the interconnection application was received, the requested online date, and the actual date that the project is cleared for interconnection. By subtracting the requested date of interconnection from the actual date of interconnection, it is possible to get the number of days the customer perceives that the interconnection is early or late. The last step to put the Making Connections and CaIS data in the same format (relative days early/late), is to convert Making Connections baseline data to days, multiplying months late by the average number of days per month.

Although the point of the original Making Connections report was to show how interconnection remains a barrier to distributed generation, the time delays in this Baseline cannot necessarily be ascribed to the utility. It is likely that some delays result from events occurring on the customer side of the project. The date the customer requests to be online may be unreasonable. The causes of a delay may have nothing to do with interconnection. With the exception of a few of the Making Connections Case Studies, the data below comes without any report of its cause. This report does not seek the cause of any unexplained delay. Testing the Time Reduction Objective, and the other Objectives as well, only requires comparing the Trendline to the Baseline to see whether the conditions of the Objective are met.

2.4.2. Time Delay Baseline

2.4.2.1. California Time Delay Baseline

There are sixteen projects in the California Time Delay Baseline—four from Making Connections, twelve from the CaIS list. For this report, Time Delay is defined as the time span to interconnect beyond what the developer thought was reasonable. The project delays range from 30 days to 286 days.

The following table shows the results for California, sorted in ascending order of length of delay in days.

Table 2 CALIFORNIA INTERCONNECTION TIME DELAYS

State	Project ID[20]	kW	Technology[21]	Time Delay Total Days
CA	13.32CA	132	PV	30
CA	0.52CA	2100	Wind	61
CA	0.01SCE	235	FC	92
CA	0.01SDGE	23,500	NGCT	100
CA	0.07SDGE	200	NGIC	117
CA	0.57SDGE	400	NGIC	117
CA	0.02SCE	1,275	NGIC	117
CA	0.03SCE	14	PV	144
CA	0.04SCE	14	PV	144
CA	0.10CA	7.5	PV/Propane	152
CA	0.22CA	37	NG Turbine	183
CA	0.05SCE	60	NGMT	201
CA	0.08SDGE	400	NGIC	240
CA	0.04SDGE	14,769	NGCT/Steam	255

[20] The Project IDs are different for CaIS data and for Making Connections. The CaIS Project IDs are comprised of a sequential number #.## (numbered sequentially for each utility by date the application was received), followed by the three- or four-letter acronym for the California utility service territory where they are located. The Making Connections Project IDs are comprised of a sequential number ##.## followed by the state two-letter code for the state in which they are located. The two most significant digits of the sequential number denote the Making Connections Case Study number (from 1-26). If the project is not included in the Making Connections Case Studies, the corresponding number in the Project ID is 0. This ID system was invented specifically for this paper because it became necessary to link up project characteristics in Making Connections and to eliminate redundancy and avoid double counting in the CaIS lists. No ID system is implemented in either original source. The ID system facilitates quick distinction between the CaIS projects and the Making Connections projects and allows tracking of specific projects and cross-referencing by interested readers.

[21] PV= Photovoltaic; NGMT= Natural gas microturbine; NGIC = Natural gas internal combustion engine; FC = fuel cell; NGCT = Natural gas combustion turbine.

CA	0.06SDGE	200	NGIC	265
CA	0.05SDGE	200	NGIC	286

2.4.2.2. Non-California Time Delay Baseline

There are 22 projects in the Time Delay Baseline for non-California states, with delays ranging from 0 to 5475 days. All non-California projects are from the Making Connections report. Table 3 shows the non-California Baseline. The Iowa wind turbine, ID #0.28IA, has a delay of 15 years; the New England Cogen plant, ID #0.57NE, has a delay of 6 years. Though these are included for illustrative purposes, they represent statistical outliers and tend to skew averages, making average Baselines higher than they should be. For this reason, the California Baseline is used to measure Time Reduction, because it's the most representative for comparison with the Trendline.

Table 3 NON-CALIFORNIA INTERCONNECTION TIME DELAYS

State	Project ID	kW	Technology	Time Delay Total Days
CO	0.29CO	100	Hydro pump	0
CO	0.50CO	1925	Cogen	0
IL	0.47IL	1200	Cogen	0
MN	0.19MN	20	Wind	0
MN	18.21MN	35	Wind	0
MN	0.41MN	600	Wind	0
MN	0.62MN	23,000	Wind	0
TX	16.37TX	500	Wind (multi sites)	0
CO	12.33CO	140	IC Engine	30
MS	3.60MS	15,000	Cogen	61
OH	20.18OH	20	PV/Wind	61
PA	17.23PA	43	Photovoltaic	61
IL	21.17IL	17.5	Wind	91
IL	0.49IL	1650	IC Engine	91
NE	0.65NE	56,000	Waste-to-energy	183
HI	14.30HI	120	IC Engine	243
NE	0.25NE	50	Cogen	365
NY	0.40NY	560	Cogen	365
MD	9.43MD	703	Steam turbine	426
NE	0.39NE	500	Cogen	730
NE	0.57NE	8000	Cogen	2190
IA	0.28IA	90	Wind	5475

2.4.2.3. National Time Delay Baseline

The National Baseline is the average of the California Baseline (Table 2) plus the Non-California Baseline (Table 3). Table 4 shows averages for each, sorted by kW size. These averages and size categories become the basis for comparison with the Trendline.

Table 4 AVERAGE INTERCONNECTION TIME DELAY BASELINES

	Average Time Delay - All (days)	Interconnection Average (days)	Delay Reduction Needed to Meet Objective
California Baseline <1MW	178	366	73
California Baseline 1MW+	157	456	0
Non-CA Baseline <1MW	523	n/a	n/a
Non-CA Baseline 1MW+	361	n/a	n/a
National Baseline <1MW	308	366	73
National Baseline 1MW+	300	456	0

2.5. Cost Reduction Objective

2.5.1. Considerations in Constructing the Baseline

Ultimately, all impacts result in a cost impact, and it is the cost reduction that is the most significant benefit for DG interconnections. While this study will endeavor to reach meaningful conclusions, four facts restrict and inform possible ways of constructing the cost metric:

- No hard cost data are available for the NREL study relative to either the cost to the utility of an interconnection study or to the cost to the developer of installing and testing required interconnection equipment;
- No hard cost data are available for the period after 12/21/2000 when the Revised Rule 21 went into effect.
- CaIS and some Making Connections projects contain time delays but no cost information.
- Most of the Making Connections costs are estimates and were not actually incurred at the time the report was written.

2.5.1.1. Using Relative Cost Data

To overcome the first two restrictions, the baseline costs were examined to assess whether they would accrue to the project under the Revised Rule 21. If the Revised Rule 21 creates a condition or conditions that eliminate the cost, that will be counted as progress toward the Cost Reduction Objective. It isn't always possible to know what conditions caused the cost in the first place since the costs of detailed interconnection studies are not available. However, the requirements in the new Rule 21 were put in place to eliminate costly interconnection fees, detailed studies, and burdensome technology-specific requirements wherever functional requirements could ensure safety and reliability of the grid. Given the myriad contingencies however, no one expects the Revised Rule 21 to be able to foresee all interconnection situations at actual sites. There are many areas where the technical requirements are not spelled out in Rule 21. In these areas, the utility has discretion. Projects in the baseline that fall into one of these gray areas will not be used, since Revised Rule 21 gives no clear advantage over the old Rule 21 situation. Constructing the cost baseline, therefore, requires a project-by-project assessment of whether Revised Rule 21 would impact the Baseline project cost. Projects with insufficient information to make a determination are excluded from the results. MC estimates, where given, are used at face value.

2.5.1.2. Carrying Cost of Money

The lack of cost data in the CaIS projects cannot be overcome, except by engineering estimates, because interconnection labor and material costs aren't available. One calculable cost associated with delay is derived from the interest rate paid for capital borrowed to finance the project. The third restriction described in Section 2.5.1 can be overcome for carrying costs by attributing an assumed cost of money to each technology and time delay, thereby quantifying its cost. That way, all CaIS projects may be included in the cost overrun Baseline and Trendline and a portion of interconnection cost overrun may be accounted for. All Making Connections projects with reported time delays can be valued in the same way. Including projects without labor and material cost overruns is equivalent to setting those cost overruns to zero—in other words, the interconnection costs what the customer *expects* that it should cost, and no more. Although this is probably not a totally accurate picture, it is a conservative assumption and useful for assessing overall cost-effectiveness.

To derive the time value of money, or carrying cost, assumptions were made about how much money is spent during the process of interconnection. This varies considerably from one project to the next, so it makes sense to choose values that represent average expenditures for each technology type. The rationale behind assessing these costs is that if the technology had been installed and the project up and running at the customers expected online date, the investment would be available to produce returns. But because of the delays, it is necessary to continue paying interest on the capital cost of the project without receiving any returns.

Many factors are involved in the overall purchase and installation cost of distributed energy resources (DERs). A recent study of the market in California for Combined Heat and Power

(CHP) contains a table of approximate cost per kW for a variety of prime movers and sizes, useful for the purposes of this paper.[22]

Table 5 CARRYING COSTS FOR VARIOUS DER TECHNOLOGIES AND SIZES

Representative On-site Generation Cost and Performance	Microturbine	Gas Engine	Fuel Cell	Gas Engine	Gas Turbine	Gas Turbine	PV	Sm Wind	Lg Wind
Size kW	50	100	200	800	5,000	25,000	10	10	1000
Heat Rate (Btu/kWh HHV)	11,741	11,147	6,205	9,382	9,125	7,699	n/a	n/a	n/a
Recov. Exhaust Heat (Btu/kWh)	4600	1600		1200	3709	2800	n/a	n/a	n/a
Recov. from Coolant (Btu/kWh)		2600	1600	2500			n/a	n/a	n/a
Package Cost ($/kW)	$350	$500	$900	$300	$300	$300	$4,000	$3,000	$800
Heat Recovery	$150	$100	$75	$75	$75	$75	$0	$0	0
Emission Controls	$0	$70	$0	$29	$51	$50	$0	$0	0
Project management	$18	$25	$45	$15	$15	$15	$45	$45	45
Site & Construction Management	$25	$35	$63	$21	$21	$21	$63	$63	63
Engineeering	$14	$20	$20	$12	$12	$12	$20	$20	20
Civil	$50	$75	$100	$38	$15	$13	$100	$100	100
Labor/Installation	$70	$100	$120	$38	$45	$45	$120	$120	120
CEMS	$0	$0	$0	$0	$30	$20	$0	$0	0
Fuel Supply-compressor	$40	$0	$0	$0	$20	$15	$0	$0	0
Interconnect/Switchgear	$50	$75	$38	$31	$10	$3	$38	$38	37.5
Contingency	$18	$25	$27	$15	$15	$15	$27	$27	27
General Contractor Markup	$78	$103	$139	$57	$61	$58	$139	$57	$61
Bonding/Performance Guarantee	$24	$31	$14	$17	$18	$18	$14	$17	$18
Carry Charges during Constr.	$15	$20	$27	$11	$24	$23	$80	$61	$45
Carry Costs per kW per day	$0.0424	$0.0555	$0.0738	$0.0310	$0.0660	$0.0633	$0.2189	$0.1672	$0.1239

The table makes the following assumptions:

- Of total construction cost, 50% has been paid during the period of interconnection delay;
- Interest rate is 7%;
- Construction (for a project without delays) takes 1 year for units 1MW+ and 6 months for units <1MW.

The final line simply divides the "Carry Charges during Construction" by days per year to show the carrying costs per kW per day. To derive the total cost overrun due to delay, the technology and size are matched to the project, and the carrying cost per kW per day is multiplied by the number of days of delay.

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[22] http://www.energy.ca.gov/reports/2000-10-17_700-00-009.PDF, Onsite Energy, "Market Assessment of Combined Heat and Power in the State of California, July 1999. PV costs come from http://solstice.crest.org/articles/static/1/binaries/REPP_FL_100202.pdf. Wind costs come from http://www.energy.ca.gov/distgen/economics/capital.html.

2.5.1.3. Lost Opportunity Cost

Perhaps the biggest cost associated with delays in interconnection is the lost opportunity cost. Opportunity costs consist of project revenue, as from sales (or avoided cost of purchase) of electricity, of an electric generator. These revenues are "lost" when there is a delay in completion of the project. In this instance, the delay of concern is for interconnection. Data on opportunity cost is usually proprietary, so a surrogate means for estimating this cost was developed, using conservative assumptions. For example, it is assumed that an investor in DG would probably not accept less than a 6.5% return on invested capital.[23] Assume that a 100kW power plant with a 50% capacity factor costs $2000 per kW installed, or $200,000. It will run 4380 hours per year and (assuming 100% operation during these hours) generate 438,000 kWh per year. A 6.5% return on $200,000 invested would equal $13,000 per year, or about $0.03/kWh. This figure is used for all units under 1 MW.

Costs per kW for units 1 MW and above are assumed to be $1000/kW, so that $0.015/kWh would generate a 6.5% return if run half time. If the operating hours are shorter—a peak shaving application, for example—the ROI per kWh would have to be higher to support the same return; and vice versa. The table below shows four common operating modes and their hours and profitability characteristics for units < 1MW. Section 3.4.3 further describes the conservatism of these ROI/kWh assumptions.

Table 6 HOURS ASSUMED FOR OPERATING MODES (UNITS < 1 MW)

Operating Modes	Hours/year	$/kWh ROI	Hours breakout
Cogeneration	5,200	$0.025	16hrs M-F; 10hrs S/S
Peak Shaving	2,080	$0.063	8hrs M-F
Primary Power	6,307	$0.021	8760 x 72% available
Emergency/Backup	100	$1.300	Extended emergency

2.5.1.4. Savings in Interconnection Fees and in Interconnection Costs

The simplified processes developed under the Revised Rule 21 have a fixed fee associated with Initial Review ($800) and with Supplemental Review ($600). Before the revised rule, all applications had to undergo an Interconnection Study. Before the Revised Rule 21, the requirements imposed on simple interconnections could be severe, because utility protection

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[23] This number is arbitrary, though probably low; DG is still a somewhat risky investment and one would expect a return commensurate with the risk.

engineers knowledgeable with interconnecting giant power plants to the transmission grid, but unfamiliar with interconnecting small plants tended to impose unnecessarily burdensome requirements. Detailed Study is estimated here to cost $7,500—a conservative figure supported by recent anecdotal evidence. The cost difference calculated for each project between old and Revised Rule 21 equals $6,100 for Supplemental Review and $6,700 for Simplified Review—average $6,400.

2.5.2. The Cost Comparison Baseline

The interconnection cost overrun per kW, the delay carrying cost per kW, lost opportunity cost, and the interconnection cost are included for every project in the Baseline for economic objectives (see Appendix A). Projects that do not have adequate cost or time data are marked "n/a". The Cost Objective has targets for units under 1MW (30% cost reduction) and for units 1MW and above (15% cost reduction). Progress toward these targets and an assessment of all costs included in the previous section (2.5.1) is described in Section 3.4.

3.0 The Cost Effectiveness of Revised Rule 21

On December 21, 2000, CPUC Decision 00-12-037 [24] approved the Rule 21 language adopted by the California Energy Commission. PG&E, SDG&E, and SCE have now replaced their former Rule 21 with the approved Model Tariff, Interconnection Application Form, and Interconnection Agreement. Each utility filed again in late 2002 to make additional changes and to increase rule uniformity, and there were several other minor filings. The Interconnection Working Group continues to consider changes to Rule 21 and its associated documents with the goals of simplifying the process of interconnection, complying with evolving tariffs, and keeping the utility implementations uniform. A third tariff Advice Letter filing is expected for all three utilities by Spring 2004. Advice Letters are changes recommended by the utilities. Upon adoption by the CPUC, they become part of Rule 21.

3.1. Process Improvement Trendline vs Baseline

While no specific process improvement Baseline was stated in the FOCUS contract, MC contains an excellent Proxy for comparison: the Ten-Point Action Plan shown in Table 1 above. To the extent that the Ten Points are fulfilled in the Revised Rule 21, then progress is being made toward the Process Improvement Objective. Table 7 shows how each of the "Ten Points" are or are not fulfilled by the Revised Rule 21. A brief narrative description of each point follows.

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[24] http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/4117.htm

Table 7 Fulfilling the Process Improvement Objective

Barrier Types	*Baseline conditions*	*Met in Trend line?*	*% Met*	*Rule 21 Code*
Technical	1. Adopt uniform technical standards...	Y	100%	Section D, I, J, Incorporating P1547 Provisions
Technical	2. Adopt testing and certification procedures...	Y	100%	Section J
Technical	3. N/A	N/A	N/A	N/A
Business Practice	4. Adopt standard...practices for...utility review.	Y	50-100%	Section C & I
Business Practice	5. Establish standard...interconnection agreements.	Y	100%	Standard Agreements
Business Practice	6. Develop tools for utilities to assess...[DER]...on the grid.	Y	50%	FOCUS-II DG Monitoring
Regulatory	7. Develop...regulatory principles compatible with [DER]...	Y	100%	Objectives of FOCUS-I
Regulatory	8. Adopt regulatory tariffs	Y	100%	Rule 21
Regulatory	9. Establish expedited dispute resolution processes...	Y	100%	Section G
Regulatory	10. Define the conditions necessary for a right to interconnect.	Y	50%	Section B.1
Total			83%	

3.1.1. Point #1: Adopt Uniform Technical Standards

Uniform technical standards have been the cornerstone of the Revised Rule 21 effort from the start. Though the Rule 21 revision effort was contemporaneous with the IEEE[25] national technical standards development (in the "P1547 Working Group"), it was never the intent of the California technical interconnection group to create a separate California "standard". In fact, it was implicit that when the national standard was released, that Rule 21 would embrace it. Meanwhile, Rule 21 worked out many of the procedural details of technical implementation of interconnection requirements. The IEEE Standards Board approved IEEE 1547 Standard for Interconnecting Distributed Resources With Electric Power Systems on June 12, 2003. It was found that the IEEE Standard was only technical, limited in scope and did not cover the wide range of issues such as grid impact evaluations addressed in Rule 21. In November 2003, the California interconnection Working Group began the process of reconciling its technical details into the technical requirements (Section D), the Initial Review (Section I), and Certification and Testing (Section J) with IEEE 1547.

3.1.2. Point #2: Adopt Testing And Certification Procedures

Section J of the Revised Rule 21, as mentioned above, completely covers procedures for Testing and Certification for interconnection equipment.

3.1.3. Point #3: Accelerate Development Of DP[26] Control Technology & Systems

As mentioned in Section 2.1 above, development of control technologies is not within the scope of the FOCUS-II subcontract, nor a part of any of the California interconnection discussion, nor

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[25] Institute of Electrical and Electronics Engineers

[26] Distributed Power

of Rule 21 itself. Therefore, this point is not applicable as a measure of progress toward the objective.

3.1.4. Point #4: Adopt Standard...Practices For...Utility Review

Section C of Rule 21 establishes standard fees and timelines for utility administration of the interconnection process. Rule 21 Section I (following Section H) lays out in detail how the utility is to review each interconnection: the set of steps or "screens" that each interconnection must pass to qualify for Simplified Interconnection. If the interconnection fails a screen or screens, it enters Supplemental Review. The Interconnection Working Group also established a less formal guideline for Supplemental Review that describes some of the steps and processes that should go on during that process.[27] Because each of the IOUs are under CPUC jurisdiction to carry out the Rule 21 tariff, Section C and Section I function in California as a standard set of requirements for utility review. While the Supplemental Review guideline does not have the authority of regulatory jurisdiction, it does serve as a template for how a utility could carry out the Supplemental Review process.

There are sections of Rule 21 that do not spell out technical details of implementation, and so give discretion to the utility staff to make technical determinations in the field. Although the Revised Rule 21 is nearly identical for the three IOUs, implementation of details not specified in the Rule varies among utilities. For this reason, this point varies from 50% to 100% fulfillment.

3.1.5. Point #5: Establish Standard...Interconnection Agreements

SDG&E, SCE and PG&E have each filed tariffs for interconnection agreements. With a few salient exceptions, the agreements are identical. For a complete description of variations between them, please see the Section 6 of the California Interconnection Guidebook.[28] SDG&E and SCE have the same set of agreements:

- Customer non-export ("Generating Facility Interconnection Agreement");
- Customer agreement for third-party installation and operation ("Customer Generation Agreement");
- Third-party non-export ("Generating Facility Interconnection Agreement (3rd Party Non-Exporting)").
- Customer inadvertent export ("Generating Facility Interconnection Agreement (Inadvertent Export)");
- Third-party inadvertent export ("Generating Facility Interconnection Agreement (3rd Party Inadvertent Export)").

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[27] The Guideline is a Working Group product that included significant input from utility and non-utility protection engineers. See URL http://www.energy.ca.gov/distgen/interconnection/SUP_REVIEW_GUIDELINE.PDF.

[28] See Publication # 500-03-083F at URL http://www.energy.ca.gov/distgen/interconnection/guide_book.html.

The primary difference between the interconnection agreements of PG&E, when compared with the agreements of SCE and SDG&E, is that there is no accommodation for inadvertent export. Therefore, there is no customer inadvertent export agreement and there is no third party inadvertent export agreement. PG&E, then, has just the first three agreements listed above.

3.1.6. Point #6: Develop Tools For Utilities To Assess...[DER]...On The Grid

The FOCUS-II contract with the Energy Commission (#500-00-013) includes Task 2.2, "Select and Monitor twelve (12) DG projects". The scope of work document states:

"The purpose of this task is to improve the cost-effectiveness of DG interconnection while maintaining the safety and reliability of the grid. This will be accomplished by gaining precise technical feedback on what effect interconnecting DG has on the local distribution grid. The FOCUS team will provide data, analysis and recommendations to the Energy Commission for its use and for the Interconnection Workgroup."

At present, 12 sites have been selected according to the criteria outlined in the monitoring plan; and instrumentation has been installed.

There are several reasons why this effort is judged here to have fulfilled 50% (rather than 100%) of the MC Action Plan point 6, requiring development of tools for utilities to assess DER. First, monitoring only 12 generators for harm to the grid will give utilities little additional confidence that the 13th generator will not cause problems. Second, Task 2.2 does demonstrate benefits to the distribution system of an interconnected generation resource. At this time, utilities have little confidence in real benefits to their distribution system with the presence of DG operating in parallel.

Task 2.2 of FOCUS-II nonetheless provides data on the behavior of DG on the grid where no data existed before.

3.1.7. Point #7: Develop...Regulatory Principles Compatible With [DER]

One of the regulatory "quiet revolutions" the Revised Rule 21 initiated was the idea of performance-based interconnection requirements (PBIRs). The old Rule 21—different for each of the three investor-owned utilities—prescribed and proscribed technological solutions to the challenges of safe and reliable interconnection of DG. For example, in certain situations, expensive electro-mechanical relays were required; digital relays that performed the same function at a lower cost were unacceptable because they didn't meet the letter of the rule. The Revised Rule 21, on the other hand, sets performance standards and allows any technology to be used that meets those standards. This approach insures the safe and reliable operation of the grid *and* drives technological innovation. Each new interconnection equipment model requires Certification by a NRTL regardless of any certification of previous models. Certification would be simpler if a new uncertified model would be allowed to use a previously Certified design as basis. PBIRs in Revised Rule 21 are described in detail in the FOCUS-I Final Report.[29] The objectives elaborated in the report include a number of "principles compatible with DERs":

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[29] See "Objective 5: Replace the current prescriptive Interconnection Requirements (IRs) with

- Objective-1: Facilitate consensus on the technical issues of Interconnection.
- Objective-2: Make Interconnection a single uniform process which is internally consistent and predictable statewide.
- Objective-3: Provide a method of Simplified Interconnection.
- Objective-4: Explore the role of advanced communications and metering for Interconnection scheduling and dispatch.
- Objective-5: Replace the current prescriptive Interconnection Requirements (IRs) with Performance-Based Interconnection Requirements (PBIRs).
- Objective-6: Lower the cost of Interconnection.
- Objective-7: Fulfill the need for interim standards.
- Objective-8: Address safety issues.
- Objective-9: Define the scope and feasibility of Type Testing.
- Objective-10: Accelerate the adoption of DG by training and informing government agencies.
- Objective-11: Define the scope of technologies covered by Rule 21.
- Objective-12: Make changes to utility tariffs proceeding from Interconnection rules.
- Objective-13: Facilitate Interconnection of small units.
- Objective-14: Eliminate utility discretion of study fees.

This Point #7 of the Action Plan is fulfilled for interconnection Rule 21. With the exception of Objective–14, where some discretion still exists, it is 100% fulfilled with the present effort.

3.1.8. Point #8: Adopt Regulatory Tariffs And Utility Incentives

Like the previous point, Point #8 seems to concern itself with many issues outside interconnection. For example, utility incentives for certain forms of distributed generation exist in California, and they have a large impact on project economics, making it considerably easier for an end-user to justify installation of DG. However, this incentive is not an interconnection issue. There are other related tariffs that also impact DG project economics that have nothing to do with interconnection (such as standby rates and exit fees). If we include all these tariffs and incentives, it is clear that the FOCUS-II interconnection work has done little to foster these other tariffs.

Performance-Based Interconnection Requirements (PBIRs)" in the FOCUS-I Final Report at: http://pier.saic.com/PDF/P600-01-006.pdf, February 2001, p24-39.

The only tariffs considered in this report to impact interconnection cost effectiveness is the Revised Rule 21 (the interconnection tariff), so this point is 100% fulfilled.[30] Evidence of fulfillment is the completed Rule itself.

3.1.9. Point #9: Establish Expedited Dispute Resolution Processes

Section G of the Revised Rule 21 has a two-step process of dispute resolution:

1. The dispute is reduced to writing—the so-called "dispute letter" and submitted to the other party along with suggestions for resolution. Disputants are required to meet within 45 days of the date of the letter to work out a resolution.
2. If no resolution emerges within the 45-day timeframe, at the request of either party the dispute may be put before the CPUC.

Although 45 days may not be what the writers of MC had in mind when they referred to an "expedited" process, it is considerably better than an unbounded process in which disputes may take a year or more to resolve.

3.1.10. Point #10: Define The Conditions Necessary For A Right To Interconnect

It is possible to consider that the Revised Rule 21 itself is the complete set of conditions necessary for a right to interconnect. This is true, at least insofar as the Rule encompasses all requirements for interconnection. It is safe to say that every provision of the Revised Rule 21 is meant to ensure the safety and reliability of the electrical system while allowing interconnection to proceed. The technical requirements in Section D are a particularly clear example of the efficacy of the performance-based interconnection requirements to establish limits that may be achieved as the market sees fit. By far the most compelling statement in favor of a *rationally pre-*determined *right* (as opposed to a right *arbitrarily* determined at the time—by fiat) is this clause from Section B.1:

> "[The utility] shall apply this Rule in a non-discriminatory manner and shall not unreasonably withhold its permission for a Parallel Operation of Producer's Generating Facility with [the utility's] Distribution System."

But the statement falls over easily: there is no universal standard of reasonableness. And although Section D is constructed to cover many technical situations, others arise that are not specifically defined. In special cases (and there is no limit to what may be determined a special case, given adequate technical reasons), the interconnection applicant has no recourse to the utility's expertise and determination in its own favor.

It is possible, under the Revised Rule 21, for the utility to declare that *any* project requires a Detailed Study. The cost of the Study alone can discourage a customer sufficiently, especially a small customer, that it abandons the effort.

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30 Though many other tariffs impact *project* cost effectiveness, Rule 21 is considered most relevant to the cost of *interconnection*.

When the Revised Rule 21 first went into effect, it was difficult for the utilities to meet the 10-day timeline for Initial Review. There is anecdotal evidence that at least one of the utilities initially solved this problem by making an immediate determination that every project required a Detailed Study. This may be connected with the fact that a large number of projects were withdrawn in that utility's service territory during the first year the Rule was in effect. The other utilities, meanwhile, met the commitment by declaring that the application was never complete, and therefore the 10-day clock never officially started. The Working Group has had discussions on this point, attempting to gain a common understanding. The willingness of the utilities involved to cooperate—and not the provisions of Revised Rule 21—has allowed the Rule to attain its current success.

Yet despite the best intentions of the framers of the Revised Rule 21, the future success of the Rule is not assured because no *right to interconnect* has been firmly established. Section B.1. above does require proof of reasonableness, though—a partial score for this point—considered here to be 50% fulfilled.

3.2. Simplified Interconnection Trendline vs Baseline

Recall from the discussion in Section 2.3, there is no such thing as Supplemental Review or Initial Review in the Baseline. Any projects that passed only did so after Detailed Study. Many Baseline projects, as noted, did not pass at all. Therefore, we count progress toward the Simplified Interconnection Objective as a decrease in the number of projects not passing and, of those passing, an increase in the ones passing after Initial or Supplemental Review. In fact the Trendline under Revised Rule 21 shows dramatic improvement over the Baseline, as shown in Table 1. In the Baseline (made up of MC projects), over 70% of projects required Detailed Study; the rest were withdrawn, suspended, or disconnected.[31] By sharp contrast, SDG&E has over 80% Supplemental Review[32], almost 17% passing after Initial Review, and just 2% withdrawn. SCE has nearly as many projects passing after Initial Review as Supplemental Review and has only 1 Detailed Study. Over 10% of its projects are suspended, however.[33] PG&E actually shows more projects passing after Initial Review than those requiring Supplemental Review. After 3 years, however, about 35% of its project applications have been withdrawn and more than 10% have required Detailed Study.[34] Many of the projects withdrawing applications in PG&E territory withdrew during 2001 and 2002 when the program was in its early stages, so there appears to be a reduction of the withdrawal rate more recently.

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31 Disconnections aren't shown here because there were none in the Trendline.

32 Given the Initial Review requirements for the use of Certified Equipment and the relatively small but growing list of Certified Equipment, the low percentage of Simplified Interconnections is to be expected. Many of the Simplified Interconnections are likely passing by means of Interim utility approval.

33 This includes only projects that are suspended and not resumed by the customer.

34 This does not include projects not yet online.

Exact distribution of PG&E interconnection status by years is unknown, since the company provided no breakout of data by year. Withdrawals occurred in PG&E territory as follows: 17 in 2001, 16 in 2002 and only 4 in the first three quarters of 2003.

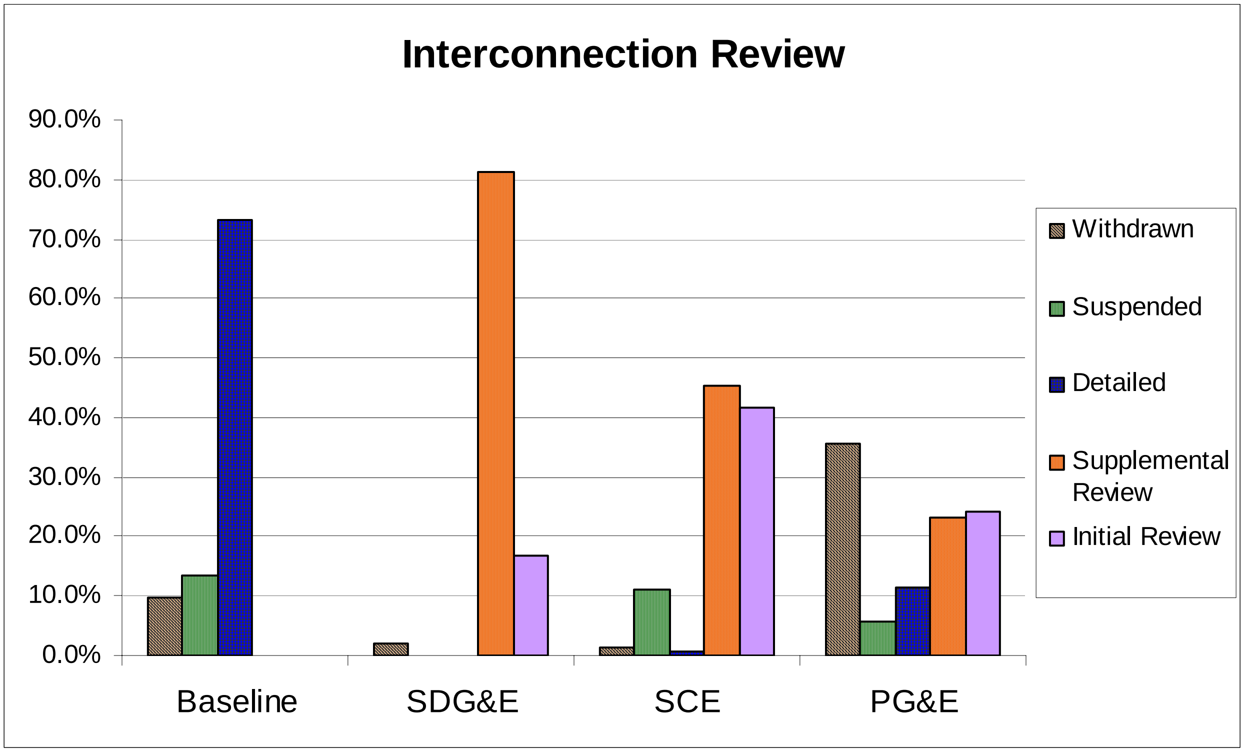

Figure 1 SIMPLIFIED INTERCONNECTION PROGRESS

One would expect a slightly higher occurrence of Detailed Studies in PG&E than in other utility territories because of the network distribution systems in the Bay Area.[35]

If we consider Initial and Supplemental Review signal of success of Revised Rule 21 to progress toward the Simplified Interconnection Objective and withdrawal, suspension and Detailed Study to signal failure,[36] then revised Rule 21 has been very successful.[37] Since the Revised Rule went into effect, roughly two out of three interconnections (74%) have been through Initial or Supplemental Review. Of the remaining interconnections, 14% were withdrawn, 7% were suspended, and 5% required Detailed Studies.

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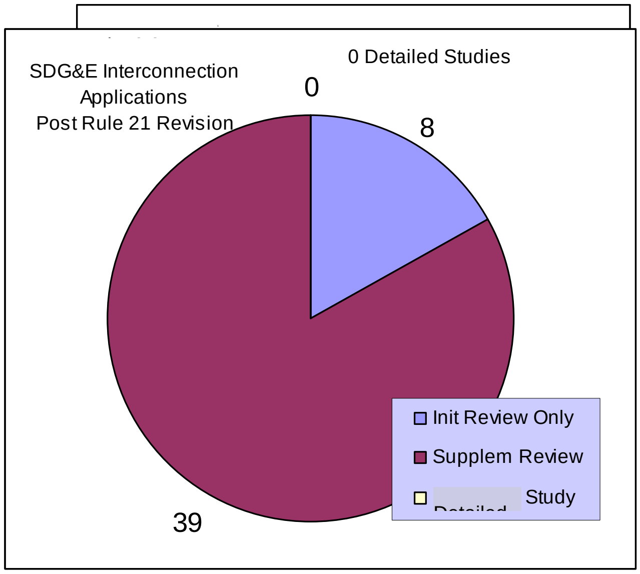
[35] Network distribution systems require technical review beyond what's needed for radial systems.

[36] Of course, any interconnection that is made is a success—even if it needs a Detailed Study; the point, though, is to contrast *progress* toward Simplified Interconnection.

[37] No NEM projects are included here.

through Figure 4 show the results of data provided by the companies, comparing the Baseline under the old Rule 21 to the Trendline under the Revised Rule 21.



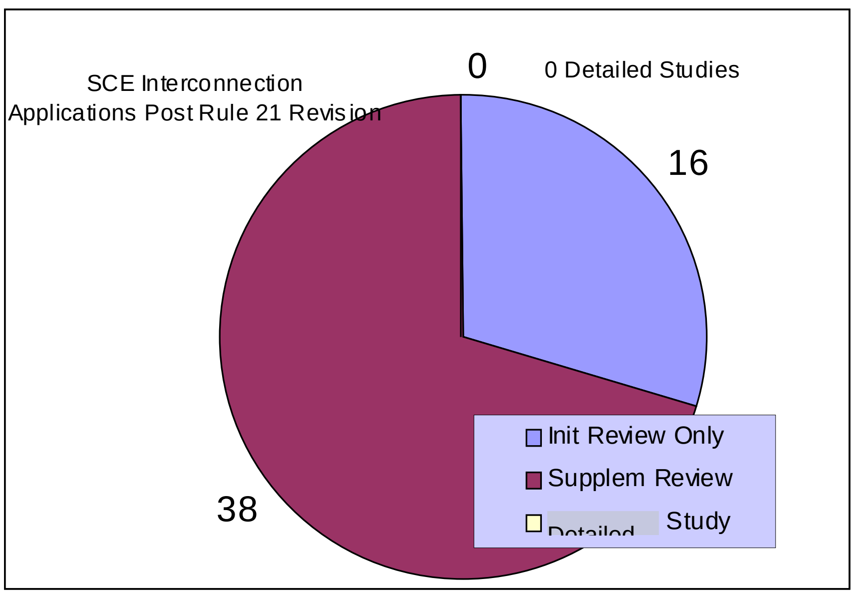


Figure 2 PG&E Interconnections

Figure 3 SDG&E Interconnections

These figures show the spread of the successful interconnections for each of the three utilities—including those that passed following Initial Review, those that require Supplemental Review and those that require a Detailed Study.

It is seen that at SCE and SDG&E, all interconnections approved since the revised Rule 21 have been achieved without a Detailed Study. At PG&E a few interconnections still require Detailed Study, but PG&E leads in the category of interconnections approved with only Initial Review.

Figure 4: All Utilities Initial & Supplemental Interconnections vs. Baseline

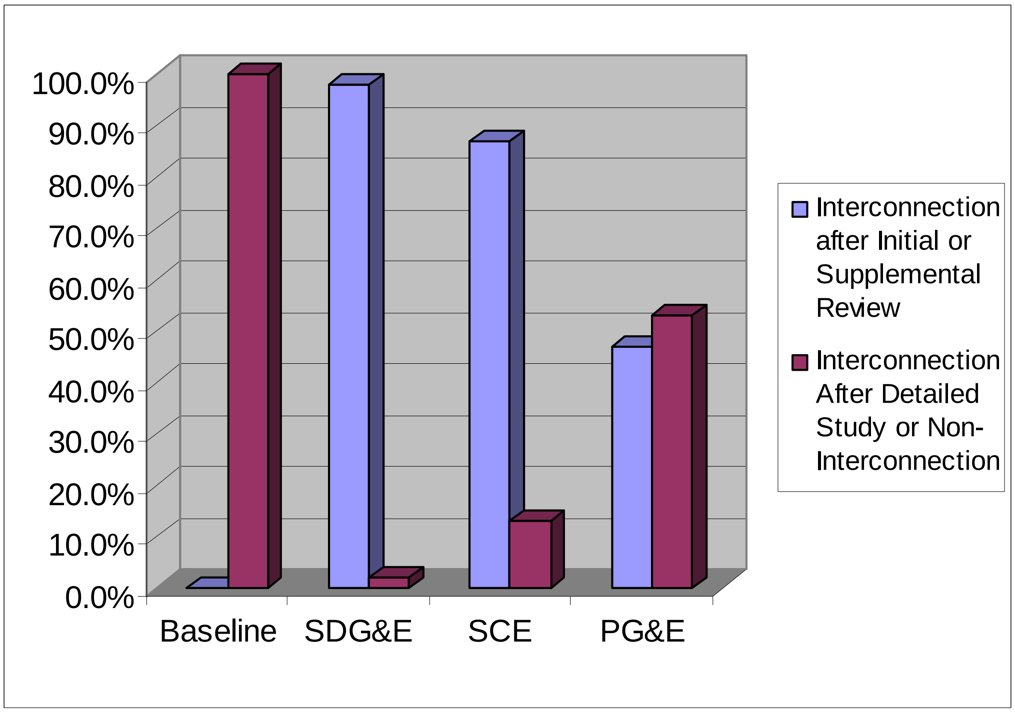


Figure 5 All Utilities Initial & Supplemental Interconnections vs. Baseline

3.3. Time Reduction Trendline vs Baseline

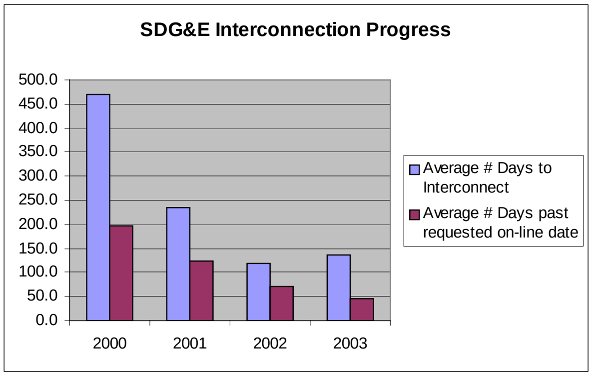
3.3.1. Trendline Analysis

The amount of time to interconnect is not necessarily a direct reflection of utility interconnection practices—there are many causes of delays of customer projects. These may be delayed indefinitely or cancelled for reasons completely unrelated to interconnection. Improvements in interconnection times may not be solely attributable to improvements in utility interconnection handling procedures; they may also indicate the increasing intelligence by developers on how to apply and interconnect distributed resources. Furthermore, "delay" is inherently a subjective term. The "requested on-line" date is relative to the customer's expectation and may be therefore unreasonably short (for example, some applications list the day the application is handed in), or long (for example "sometime within the next 5 years"). The cost data are also relative to customer expectations and so must be treated with this limitation in mind. Yet, it may be said, it is getting easier and faster to interconnect in California under the Revised Rule 21.

- Communication among and between utilities and other stakeholders has improved;
- Utilities and third-party applicants have scaled the learning curve;
- Utilities now have staffing to handle DG applications from beginning to end;
- PG&E has a new Interconnection Services business unit to handle applications from their large and diverse service territory.

Customers and utilities alike deserve credit for these improvements. Year 2000 projects depicted below are in the CaIS Baseline. There are dramatic improvements in all utility territories.[38]

[38] There is no written standard for exactly how the utilities should count times, however, which may explain some divergence in their results.



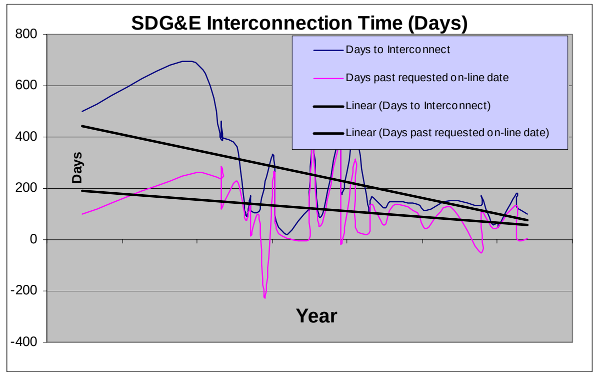
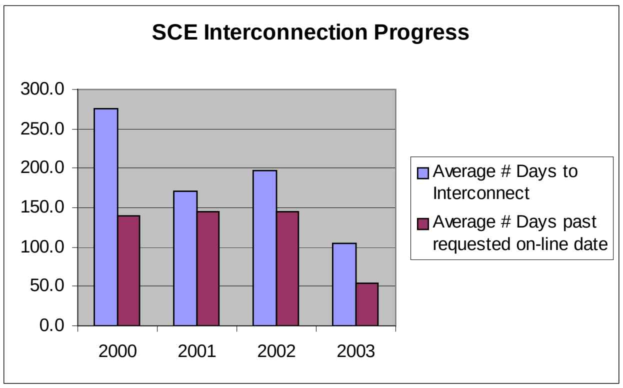


Figure 6 SDG&E ANNUAL PROGRESS

Figure 7 SDG&E PROJECT DELAY



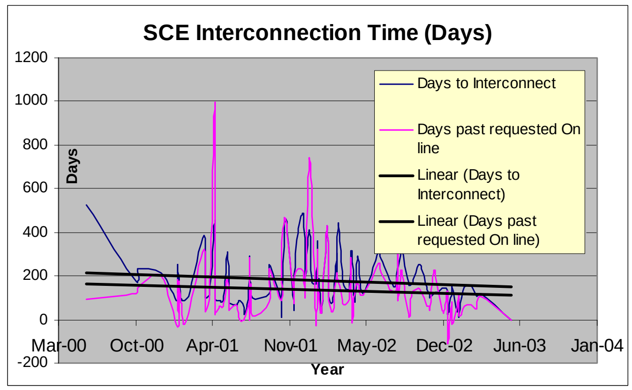
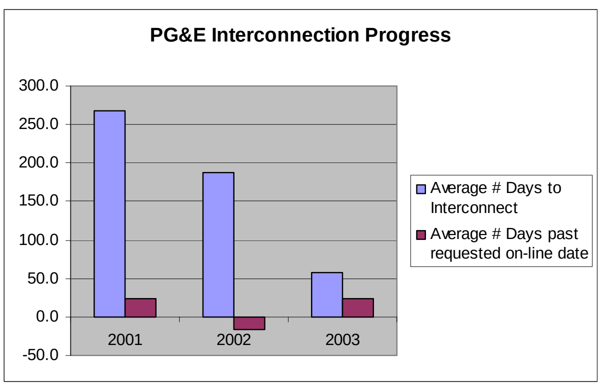


Figure 8 SCE Annual Progress

Figure 9 SCE Project Delay



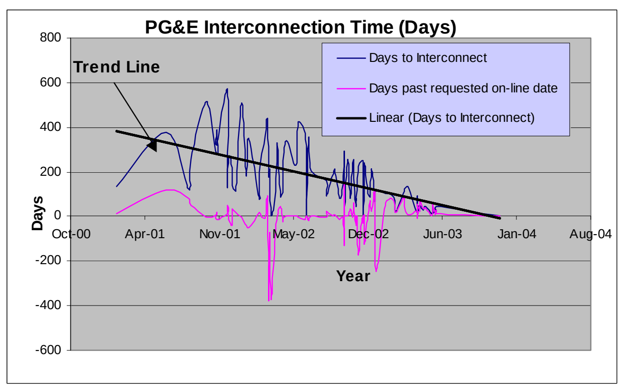


Figure 10 PG&E Annual Progress

Figure 11 PG&E Project Delay

In SDG&E territory, average number of days to interconnect has improved by almost 100% two years in a row. Average days past requested on-line date improves over the 4 years tracked by a total of 200%. Though PG&E had no interconnections in 2000, by 2003 it reduced average overall interconnection time to less than 60 days. Their average interconnection time delay was negative in 2002, meaning that their average customer set expectations at a point later in time than the interconnection was delivered. In years 2001 and 2003, PG&E's time delay has been less than 25 days, best of the IOUs. Results for all utilities combined (Figure 12) are similar. The annual progress is remarkable and in large measure attributable to the changes introduced by Revised Rule 21.

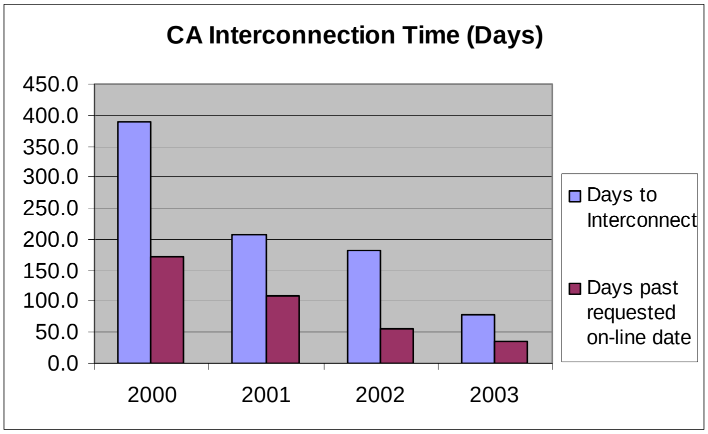


Figure 12 CALIFORNIA ANNUAL PROGRESS

3.3.2. Trendline vs Baseline Comparison

The Time Reduction Objective was to achieve a 20% decline in time to interconnect for units under 1MW. The Trendlines for units <1MW and for units 1MW and above for years 2001-2003 compared with the National, California and non-California Baselines established in Section 2.0 are depicted in Figure 13.

The results show that the Time Reduction Objective of 20 percent is exceeded every year under the Revised Rule 21 by a large margin, no matter which Baseline is used. In fact, the time delay and overall time to interconnect projects larger than 1MW is also reduced by more than 20% every year as well. In 2001, total days to interconnect are reduced by 39% for projects less than 1MW, and by 61% for projects larger than 1MW. Time to interconnect in 2001 is reduced by 33% to 79% for projects less than 1MW, and by 22% to 62% for projects larger than 1MW. In 2002, total days to interconnect are reduced by 52% for projects less than 1MW, and by 53% for projects larger than 1MW. Time to interconnect in 2002 is reduced by 66% to 89% for projects less than 1MW, and by 61% to 85% for projects larger than 1MW. In 2003, total days to interconnect are reduced by 79% for projects less than 1MW, and by 82% for projects larger than 1MW. Time delays in 2003 are reduced by 78% to 93% for projects less than 1MW, and by 89% to 96% for projects larger than 1MW.

These numbers have a high degree of credibility, due to the credibility of the source and sheer quantity of the data. Time reductions exceed the Objective target and are the most direct measure of achievement of the Revised Rule 21.

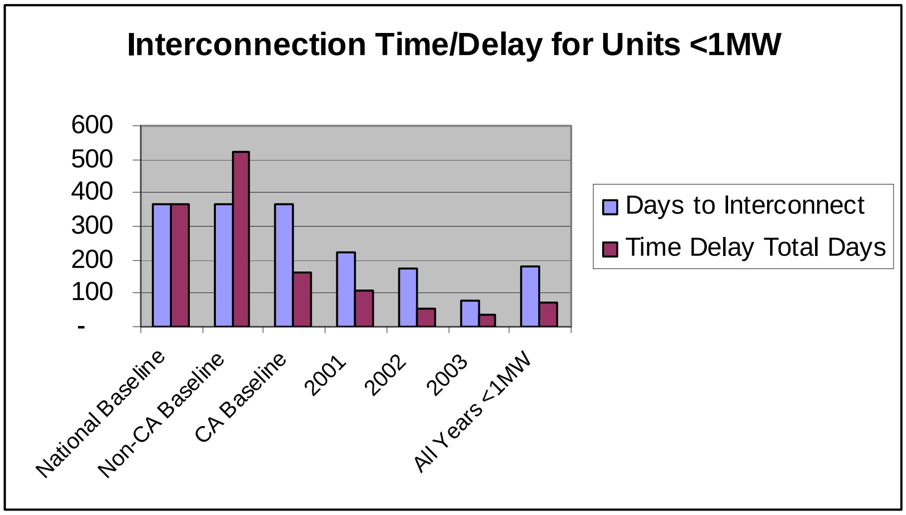


Figure 13 Time Delay Trendline (All CA IOUs) vs Baseline Units <1MW

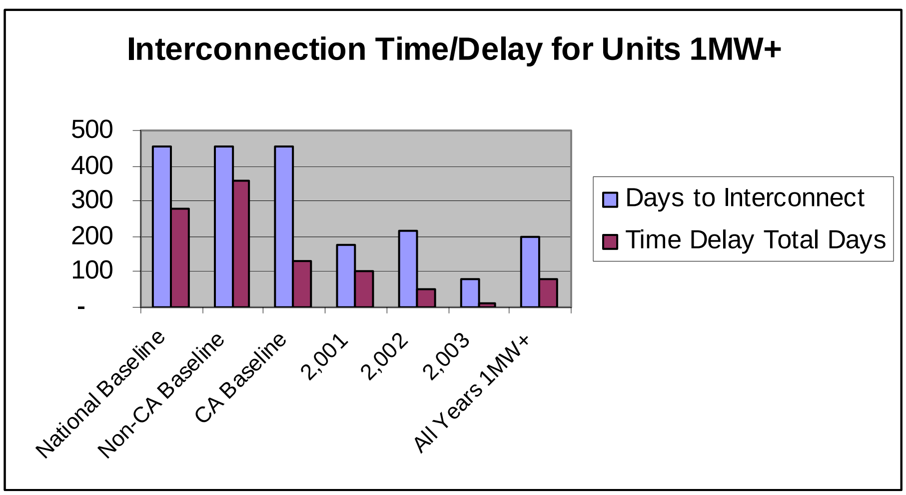


Figure 14: Time Delay Trendline (All CA IOUs) vs Baseline Units 1MW+

3.4. End-User Interconnection Cost Comparison

The CaIS projects contain no data on interconnection cost to the end-user. MC gives Baseline costs only for items that customers perceived as unreasonable. This complicates calculating interconnection cost reduction to the end-user but the calculation may still be performed with reasonable accuracy by comparing Baseline costs with treatment under Rule 21 of those same costs. Sections 3.4.1 and 3.4.2 will discuss the cost comparison Trendline and fulfillment of the Cost Reduction Objective; Section 3.4.3 will discuss the over all cost effectiveness of the FOCUS project and revised Rule 21.

3.4.1. End-User Interconnection Cost Analysis

This analysis is constructed using only the cost reduction Baseline projects treated as if Revised Rule 21 were in effect, to gauge whether cost reductions would result. This is a judgment made with only partial interconnection information since no detailed site information is available. Where no explanation for cost data is available in the Making Connections report, the project is removed from the Trendline. NEM projects are eliminated. After following this procedure for each of the cost reduction Baseline projects,[39] four projects are left. A description follows of the cost reductions available under Revised Rule 21 for each of these projects.

Of the projects from MC with identifiable cost reductions under Revised Rule 21, 1 is in California, 3 are in other states. All are less than 1MW. The lack of data on projects over 1MW makes Cost Reduction Objective results in this size range unavailable. As projects become larger (especially as a ratio to existing electric distribution system circuit capacity), they often require more utility study and are more likely to require facility or distribution system upgrades. These costs may be more attributable to the location of the DG involved than they are to the utility interconnection regulations, so that costs become less easily attributed to the revisions of Rule 21. Having no cost data for larger projects further reduces the certainty of conclusions in this size category.

High cost for MC projects is relative, as mentioned previously. That means some costs are expected by the customer, and not considered to be excessive; others are not expected and appear to be excessive because they do not fit any expectation. Though relative cost data makes conclusions less certain, it is possible to complete the analysis by isolating the technical requirement in the MC project, then determining whether revised Rule 21 has the same requirement or not. If so, the cost under revised Rule 21 is computed; if not, the cost becomes $0. All costs normally associated with interconnections passing with Simplified Interconnection or Supplemental Review are considered “expected”; Detailed Study costs are considered “unexpected”—since they were the prevailing condition before Rule 21, and are used today only when Initial and Supplemental review fail to solve the interconnection issues under normal utility review. The expectations assume a customer that is technically astute but not conversant with Rule 21.

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[39] From Making Connections only, the CaIS projects having been excluded already.

Expected costs will include:

- Protection at the PCC (for each meter);
- Utility charge for the commissioning test.
- Interconnection study cost;
- Net Generation Output Meter (for each meter);[40]

Unexpected costs include:

- Detailed Study additional equipment and engineering.
- Redundant protection requirements for over/under voltage and over/under frequency;[41]

Reconstructing the costs for the following projects is a four-step process:

1. Compare the cost overrun issue as reported in MC;
2. Determine the cost under revised Rule 21;
3. Determine whether there are any "unexpected costs;
4. Total the cost savings or increase.

In most cases, Revised Rule 21 eliminates 100% of what MC calls the "barrier related cost".

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[40] NGOM is not required by Rule 21, but by other utility tariffs.

[41] This has been required in some field situations by utilities in California—post Revised Rule 21.

Table 8: Estimated Trendline Interconnection Costs

		Simplified Interconnection	Supplemental Review Interconnection	Detailed Study Interconnection
Interconnection Study	Cumulative Cost	$800	$1,400	$8,900
Protection at PCC ($ per Meter)	Hardware Labor	$0 $0	$3,000 $9,000	$3,000 $9,000
Redundant Anti-Islanding	Hardware	$0	$0	$1,500
Protection ($ per Meter)	Labor	$0	$0	$1,000
Net Generation Output Meter ($ per Meter)		$0	$5,000	$5,000
Additional Requirements	Equipment & Engineering	$0	$0	$59,500
Commissioning Testing	Customer/Vendor Pre-test	$5,000	$7,500	$7,500
	Commissioning test	$3,000	$5,000	$5,000
TOTAL		$8,800	$30,900	$100,400

NOTE: All costs are engineering estimates only, not actual costs.

3.4.1.1. Example MC Case #15—75kW Microturbine in California (ID #15.27)

Developers of this project reported that the utility told them they had no obligation to interconnect them and wouldn't be able to because they were not a Qualifying Facility as defined under PURPA.[42] Later, the utility agreed to attempt the interconnection under an "experimental" or "test" interconnection agreement.[43] The utility indicated that it would

[42] Public Utility Regulatory Policy Act of 1978.

[43] "Making Connections", p. 64.

require the project developer to pay for a "method of service study required for all...facilities except [Net Energy Metered] projects." The utility indicated that this could cost up to $50,000 and take six months to perform; they also said the study cost was "non-negotiable" and that if the developer didn't pay, it would have to abandon the project.[44] Therefore, the developer added a projected cost overrun of $50,000 to the budget.

No 75kW microturbines are Certified (at this date), so this project would not qualify for Simplified Interconnection. It is *not* likely that a Detailed Study would be required for a non-exporting project of this size. The study cost, then, would be for Supplemental Review. A technically astute customer would expect to pay for a protective device at the PCC, and would expect a utility commissioning test prior to permission to run.

Revised Rule 21 eliminates 100% of this barrier-related cost.

Baseline (MC) costs

Original MC cost (for interconnection study) = $50,000;

Revised Rule 21 costs

Estimated Rule 21 cost (for interconnection study) = $1,400

Cost Reduction due to Revised Rule 21 = $48,600

Expected Costs

Expected protection at the PCC = $12,000

Expected utility commissioning test = $5,000

Study costs (Supplemental) = $1,400

Net Generation Output Meter = $5,000

Customer/Vendor pre-test = $7,500

Unexpected Costs

None

Total cost savings under Revised Rule 21 = $48,600 = 97% reduction

44 Same as above.

3.4.1.2. Example MC Case #14—120kW Propane Gas IC Engine (ID# 14.30HI)

As in other Baseline projects mentioned above, the utility in this case was asking for extra protection, beyond what the manufacturer of the generator had already provided. "The utility required synchronizing equipment and parallel operation monitoring for the induction generator that has a reverse power relay installed [already] that shuts down the entire cogeneration plant. This cost was $7,000[45] for equipment that the developer argued was unneeded."[46]

Revised Rule 21 requires protection at the PCC, but is silent on the requirement for redundant reverse power protection. To the extent that reverse-power and other interconnection functions are provided by the manufacturer protection package, the utility, at its discretion, can allow those functions to serve as reverse power protection or it may require redundant protection. Allowing the manufacturer protection to suffice does not presuppose that the utility accepts the functionality of the manufacturer's protection package. There are new options in Revised Rule 21 for the utility to satisfy itself, other than simply requiring additional protection:

- The interconnection device can be Certified by a NRTL;
- The interconnection device can receive interim certification from the utility;
- The utility can do field tests to satisfy itself.

Only four IC engines (from a single manufacturer) are currently Rule 21-Certified, and all are smaller than 100kW. It is reasonable to assume that the IC engine in this example isn't Rule 21-Certified, so the interconnection would require Supplemental Review.

Redundant protection cost is estimated at $3,500. Under Revised Rule 21, synchronizing equipment (estimated at $7,000 - $3,500 = $3,500) is not required, reducing that portion of the interconnection cost.

Baseline (MC) costs

Original MC cost for synchronizing equipment and reverse power relay = $7,000

Revised Rule 21 costs

Estimated cost:

For synchronizing equipment = $0

For redundant reverse power relay = $3,500 (may be required)

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45 The figure of $7,000 is used as the total "barrier-related cost".

46 "Making Connections", p. 62.

Expected Costs

Expected protection at the PCC = $12,000

Expected utility commissioning test = $5,000

Study costs (Supplemental) = $1,400

Net Generation Output Meter = $5,000

Customer/Vendor pre-test = $7,500

Unexpected Costs

For redundant reverse power relay = $3,500 (may be required)

Total cost savings under Revised Rule 21 = $3500 = 50% reduction

3.4.1.3. Example MC Case #12—140-kW Gas IC Engine (ID# 12.33CO)

The issue in this case was power factor. MC states, "The utility initially required the customer to bring the total facility power factor up to .90 from an average of .86—this would have required the customer to install capacitor banks, or capacitors on many of its inductive loads in the building to correct the power factor. ... In the opinion of the project manager, the requirement should be for the generators to supply their fair share of the VARs, and no more."

The technical solution provided to this problem under the Revised Rule 21 is in Section D2f:

> **Power Factor.** Each Generator in a Generating Facility shall be capable of operating at some point within a power factor range of 0.9 leading to 0.9 lagging. Operation outside this range is acceptable provided the reactive power of the Generating Facility is used to meet the reactive power needs of the Host Loads or that reactive power is otherwise provided under tariff by Electrical Corporation. The Producer shall notify Electrical Corporation if it is using the Generating Facility for power factor correction.

Under the Revised Rule 21, the customer can advise the utility that it will use the generator to provide all, or a portion of, the reactive power required to bring the facility power factor up to 0.9 lagging. This may require active control of the generator's reactive power output to maintain a 0.9 value at the PCC. MC states, "The installation ultimately resulted in an additional charge of $3000 for equipment that was considered redundant and a $2000 equipment testing charge that was considered unnecessary." Under Revised Rule 21, these charges may have been eliminated. The project would require Supplemental Review, however.

Because Rule 21 explicitly gives options to power factor correction, that cost may be waived.

Baseline (MC) costs

Original MC cost = $3000;

Additional cost = $2,000

Total cost overrun for power factor correction = $5,000

Revised Rule 21 costs

Rule 21 cost for power factor correction = $0

Expected Costs

Expected protection at the PCC = $12,000

Expected utility commissioning test = $5,000

Study costs (Supplemental) = $1,400

Net Generation Output Meter = $5,000

Customer/Vendor pre-test = $7,500

Unexpected Costs

None

Total cost savings under Revised Rule 21 = $5,000 = 100% reduction

3.4.1.4. Example MC Case #9—703-kW Steam Turbine in Maryland (ID# 9.43MD)

As with many of the MC examples, this project met significant resistance from the utility and from the whole interconnection environment, including:

- The customer paid for a utility study that the utility then discarded;
- The customer fulfilled the utility technical requirements, only to have a new set of technical requirements added on;
- The utility demanded to have operational control of the generator;
- The project experienced two years (and counting) of delay;
- No utility point person was established;
- No dispute resolution process was available;
- There was no PUC support for dispute resolution in the case;
- There was no technical procedure for dealing with networks.

All of these issues, it may be safely stated, have been successfully handled in the procedures of the Revised Rule 21—except the last. There is no clear technical approach at this date for handling network interconnection. It is still a costly and unclear procedure. This fact has a significant bearing on the outcome of the cost effectiveness of the project, as will be shown.

Revised Rule 21 does have an Initial Review screen that requires all DG projects located on a network to undergo a Supplemental Review. At this time there is no technical guide for Supplemental Review for networks. "The direct costs incurred in meeting the interconnection standards were $88,000." Additionally, "...the project owner paid for $44,000 in fees incurred by consultants for the utility to design the requested network protection. Upon completion, the utility expressed dissatisfaction with the result, and started [over]."[47] It is unclear whether this is equivalent to a "Detailed Study"—but, in any case, it is unlikely that an interconnection today that would be subject to the cost for an unused study. One other fact is necessary to this cost reconstruction: "...the building is served by three 13.8-kV distribution feeders." This is interpreted to mean that the building had three utility services, tripling some protection costs.

Baseline (MC) costs

Original cost overrun (MC)= $88,000

Additional cost (MC) = $44,000

Total cost overrun (MC) = $132,000

Revised Rule 21 costs

Estimated Rule 21 cost = $59,500 + $7,500 = 67,000 (See Table 8.)

Expected Costs

Expected protection at the PCC = $12,000 x 3 = $36,000

Expected utility commissioning test = $5,000

Study costs (Supplemental and Initial) = $1,400

Redundancy protection = $2,500 x 3 = $7,500

Net Generation Output Meter = $5,000 x 3 = $15,000

Customer/Vendor pre-test = $7,500

Unexpected Costs

Study costs (Detailed) = $7,500

[47] Both quotes from "Making Connections", p. 54.

Estimated network protection equipment & engineering = $59,500

Revised Cost overrun = $67,000

Total cost savings under Revised Rule 21 = $67,000 = 49% reduction

3.4.2. Trendline Summary

It is possible to gain further insight into the end-user interconnection cost effectiveness Trendline by summarizing the above results. All four cases produce positive savings in the Trendline over the Baseline. A weighted average of the cost savings of these projects shows an end-user cost savings of 74%. This meets the Cost Reduction Objective for projects <1MW (30%), and exceeds it by 44%. Assuming similar results for units 1MW+, the above exceeds the Cost Reduction Objective for projects 1MW+ by 59%. From the view of these reconstructed interconnection costs to the end-user, the Cost Reduction Objective is met.

Table 9 SUMMARY OF TRENDLINE END-USER COST SAVINGS

Case #	*Technology*	*kW*	*MC Cost Overrun*	*Cost Under Rule 21*	*MC Cost Overrun $/kW*	*Total Cost Savings*	*Cost Savings $/kW*	*Percent of Cost Reduction*
Case #15	NGMT	75	$50,000	$1,400	$667	$48,600	$648	97%
Case #14	Propane IC	120	$7,000	$3,500	$58	$3,500	$29	50%
Case #12	NGIC	140	$5,000	$0	$36	$5,000	$36	100%
Case #9	Steam turbine	703	$132,000	$67,000	$188	$65,000	$92	49%
Statewide average							**$201**	**74%**

3.4.3. Total Cost Savings from Revised Rule 21

Totaling lost opportunity savings, project carrying cost savings and interconnection fee savings shows significant savings for the first three years of Revised Rule 21 for projects under 1MW and for projects 1MW and above. For all projects in a given year and size range, the savings were calculated in the following manner:

1. The Lost Opportunity savings assumes a 6.5% minimum return (at 50% capacity factor and $2,000/kW installed cost), equaling lost revenue of $0.03 per kWh for units less

than l MW, (same capacity factor at $1,000/kW installed), equaling $0.015 lost revenue for units 1MW+ as a result of the delay;[48]

2. The Carrying Cost savings were calculated from Table 5;
3. The Interconnection Fee savings were assumed to be $6,400—the difference of the fee for a Detailed Study (assumed to cost $7,500) and an average of Simplified Interconnection and Supplemental Review fees (($800 + $1,400)/2);
4. No value was ascribed to system benefits, even though some stakeholders have argued that system benefits (that is, benefits to the transmission and distribution system) of DG can be as high as $0.036 a kWh.[49] These system benefits have only recently begun to be treated as providing value in select cases, and therefore were not used for this study.

In 2001, savings were over $7 million; in 2002, they were over $10 million; and almost $15 million in 2003. **Total savings for all three years is $34,116,994.**

Table 10 Total Annual Cost Savings from Revised Rule 21

	Savings in 2001 < 1MW	***Savings in 2001 1MW+***	***Savings in 2002 < 1MW***	***Savings in 2002 1MW+***	***Savings in 2003 < 1MW***	***Savings in 2003 1MW+***
Lost Opportunity Savings	$476,754	$2,926,241	$1,415,538	$5,131,287	$2,151,112	$7,994,888
Carrying Cost Savings	$373,116	$3,641,811	$888,018	$2,350,196	$1,349,471	$3,661,763
Interconnection Fee Savings	$294,400	$179,200	$576,000	$121,600	$435,200	$150,400
TOTALS	$1,144,270	$6,747,252	$2,879,556	$7,603,083	$3,935,783	$11,807,051

Measured against approximately $750,000 incurred by the Energy Commission each year for the last four years, the benefit/cost ratio for benefits already accrued is more than 10 to 1. Measured against savings projected through the next ten years, the benefit/cost ration is in the range of 100-300 to 1. The efforts expended by the Energy Commission[50] to promote Simplified Interconnection have proved to be a major success.

48 Estimated fleet capacity factor, based on actual operating modes of CaIS projects is 42.6% for units < 1 MW and 41.3% for units 1MW+. Using 50 % capacity factor understates the lost opportunity cost which is $0.035/kWh for units < 1 MW and $0.018 for units 1MW+.

49 Howard Feibus, “White Paper on Benefits of DG”, 2003, Electrotek.

50 There have been many participants in the Rule 21 Working Group meetings whose tremendous time contributions (not to mention the utilities’ donation each month of meeting space) over the past three years are not calculated into this cost/benefit.

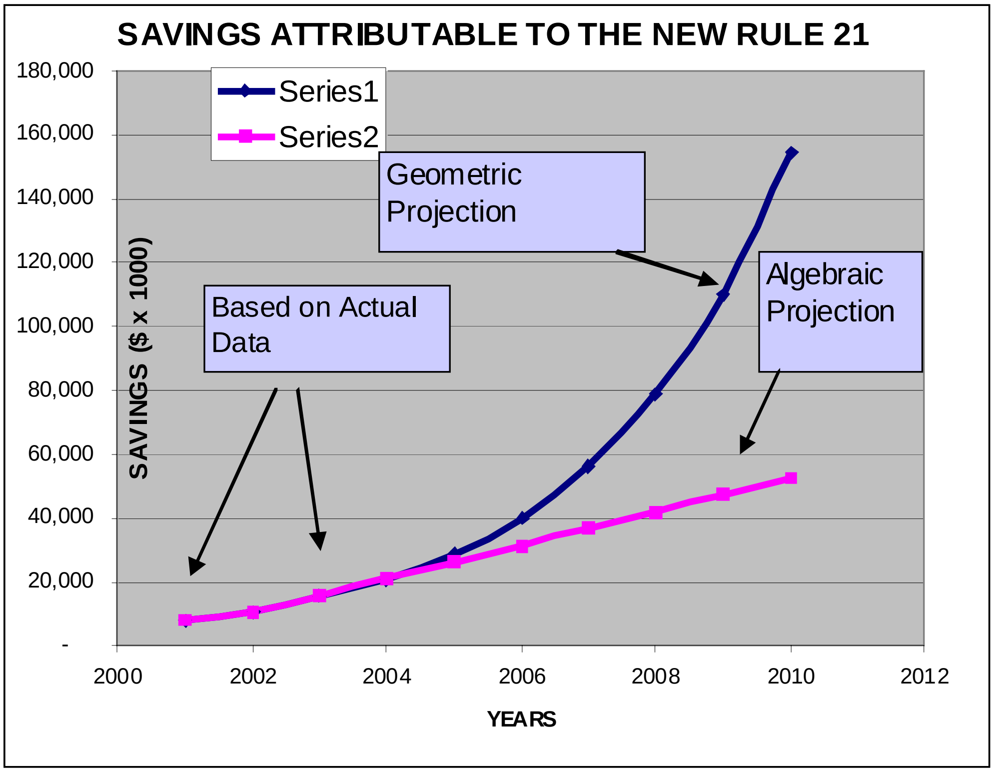

Figure 15 Projected Savings From Revised Rule 21

4.0 Results, Conclusions and Possible Improvements

4.1. Meeting Project Objectives

The objectives of the FOCUS Project are as follows, with a response to each objective provided below it:

1. Process Improvement Objective

   Evaluate whether Revised Rule 21 has improved the process of interconnection of DG to the electrical system;

This objective, as evidenced by the substantial reductions in time and cost to interconnect, has been met. As demonstrates, Revised Rule 21 eliminates more than 83% of the interconnection barriers identified in the Making Connections report. Additionally, all stakeholders continue to attend the Rule 21 Working Group meetings, almost all of them feel that the process has greatly improved, costs are lower, delays have been drastically reduced, and working relationships have greatly improved. The process has educated all parties in the intricacies of interconnection, has created a greater appreciation on each side of the difficulties faced by the other, and has caused both sides to use interconnection specialists to resolve problems, further streamlining the process.

2. Simplified Interconnection Objective

   Assess the potential for simplifying Rule 21 further to expand the types of different **applications eligible for a "Simplified Interconnection" and thus improve the cost-effectiveness of interconnection.**

More than 27% of Revised Rule 21 interconnections have qualified as Simplified Interconnections. Prior to the revisions, of course, no interconnections were Simplified. A number of generators models of different technologies have been Certified under Rule 21, including:

- Capstone Turbine
  - Model 330, 30 kW Microturbine Generator
  - Model 60, 60 kW Microturbine Generator
- Fuel Cell Energy
  - Model DFC300A-S, (Using a UL-Listed, SatCon Power Systems Canada, Ltd Model AE-462-60-F-A Inverter)
  - Model DFC1500, 1000 kW Direct FuelCell (DFC) Powerplant
- Plug Power
  - Model SU1PCM-059622, 5 kW Fuel Cell
- Tecogen

- Model CM60H, 60 kW Induction Generator
- Model CM60L, 60 kW Induction Generator
- Model CM75H, 75 kW Induction Generator
- Model CM75L, 75 kW Induction Generator

The economic objectives assessed in this Report are as follows:

3. Time Reduction Objective

   Reduce the costs associated with delays in approval and installation of interconnection by more than 20 percent for projects less than 1 MW.

The national baseline average time to interconnect was 366 days for projects under 1 MW (Figure 3-13), and 456 days for projects over 1 MW (Figure 3-14). In 2003, the average time to interconnect in California was 76 days for projects under 1 MW and 82 days for projects larger than 1 MW. This represents reductions of 80% and 82% respectively, a dramatic improvement.

4. Cost Reduction Objective

   Reduce the cost of interconnection below what was experienced prior to the Revised Rule 21 by 30 percent for units less than 1 MW and by 15 percent for units equal to or greater than 1 MW;

The cost of interconnection and the savings achieved is shown in Table 3. The end-user interconnection cost savings (as compared to the baseline costs prior to revisions to Rule 21) is $201/kW—a cost reduction of 74%. All units included in the analysis were under 1MW. Data for calculating interconnection cost savings for larger units were not available at the time of this writing. However, estimated lost opportunity savings, carrying cost savings, and interconnection fee combined savings for years 2001 through 2003 are $26,157,386 for units larger than 1 MW; estimated savings for units less than 1 MW for these categories are $7,959,608.

Over and above the savings depicted here, there other intangible benefits. There used to be a very high level of uncertainty among developers associated with interconnection. This uncertainty has largely disappeared. Developers now routinely accept that there is an effective process in place, that there are knowledgeable individuals at each utility who are responsible for interconnections, that they have recourse within the utility and at the CPUC should problems arise. Utilities have streamlined their interconnection teams, have supported certification of systems, have begun to hold interconnection seminars, and are largely reconciled to the notion that DG is a reality and part of the distribution system. Perhaps the most telling measure of success is that several other states and Canadian provinces have begun to model their interconnection rules on California's new Rule 21.

4.1.1. Rule 21 Impact on Municipal Utilities

The Los Angeles Department of Water and Power , the Sacramento Municipal Utility District, the Cities of Riverside, Pasadena, the Imperial Irrigation District and several other municipal utilities have begun adopting their own versions of Revised Rule 21 and are very active members of the Working Group. This is a testament to the success of Revised Rule 21.

4.2. Conclusions

The Revised Rule 21 has made dramatic improvements to interconnecting in California. Interconnection timeframes are now measured in weeks rather than in months. There have been significant savings that accrue as a result of the reduced time to interconnect. End-user costs of interconnection have dropped also, particularly for Certified systems. The strategy of developing certifying procedures for interconnection systems has proved successful. Most smaller systems being installed today are Certified systems and rapidly approved. The Rule 21 Working Group that is chaired by the Energy Commission has proved to be a very effective tool. The objectives of the FOCUS program have been exceeded.

4.3. Potential Improvements in Rule 21 Cost Effectiveness

The following areas related to Rule 21 should continue to be addressed:

- Improvement: Increase the number of Rule 21-Certified systems, and certify larger systems;
- Impact: Increase the number of Simplified Interconnections, thereby further reducing cost and time to interconnect.
- Improvement: Consider establishing a list of certified relays, switchgear and other interconnection equipment that is acceptable by the utilities for use with interconnections;
- Impact: Increase the number of Simplified Interconnections, thereby further reducing cost and time to interconnect.
- Improvement: Integrate the newly adopted IEEE 1547 standard for Interconnection of Distribute Resources into Rule 21;
- Impact: Bring Rule 21 technical standards into line with national standards to allow manufacturers to build one device to meet interconnection requirements in all 50 states (provided they all adopt IEEE 1547), lowering product cost and increasing the market for DG.
- Improvement: Develop processes for the most special cases, such as multiple similar and dissimilar generators at one site, metering issues deriving from tariffs, recent legislation and regulations;

- <u>Impact:</u> Reduce dissimilarity in treatment of cases where requirements are not specified in Rule 21, thereby reducing installed cost and associated time delays.
- <u>Improvement:</u> Develop requirements for networks
- Improvement: Develop requirements for export

Appendix A: Cost and Time Baseline Data

State	Project ID	kW	Technology	IC Cost Overrun $/kW	Delay Carrying Cost $/kW	Lost Opportunity Cost $/kW	Detailed Study Interconnection Fee $/kW
CA	0.03SCE	14	PV	n/a	$32	$51	$0
CA	0.04SCE	14	PV	n/a	$32	$51	$0
CA	0.05SCE	60	NGMT	n/a	$9	$72	$125
CA	0.05SDGE	200	NGIC	n/a	$16	$102	$38
CA	0.06SDGE	200	NGIC	n/a	$15	$94	$38
CA	0.07SDGE	200	NGIC	n/a	$6	$42	$38
CA	0.01SCE	235	FC	n/a	$4	$33	$32
CA	0.08SDGE	400	NGIC	n/a	$13	$85	$19
CA	0.57SDGE	400	NGIC	n/a	$6	$42	$19
CA	0.02SCE	1,275	NGIC	n/a	$5	$42	$6
CA	0.04SDGE	14,769	NGCT/Steam	n/a	$11	$91	$1
CA	0.01SDGE	23,500	NGCT	n/a	$4	$36	$0
CA	0.10CA	7.5	PV/Propane	$0	$33	$54	$0
CA	0.16CA	12	Photovoltaic	$0	n/a	n/a	$0
CA	0.22CA	37	NG Turbine	$243	$8	$65	$203
CA	15.27CA	75	Microturbine	$667	n/a	n/a	$100
CA	13.32CA	132	Photovoltaic	$189	$7	$11	$57
CA	0.52CA	2100	Wind	$19	$8	$22	$4
IL	21.17IL	17.5	Wind	$17	$15	$33	$0
MN	0.19MN	20	Wind	$325	$0	$0	$0
OH	20.18OH	20	PV/Wind	$0	$10	$22	$0
MD	19.20MD	25	Photovoltaic	$0	n/a	n/a	$0
MN	18.21MN	35	Wind	$0	$0	$0	$0
PA	17.23PA	43	Photovoltaic	$814	$13	$22	$0
CO	0.24CO	50	NG Turbine	n/a	n/a	n/a	$150
NE	0.25NE	50	Cogen	$1,000	$20	$130	$150
IA	0.28IA	90	Wind	$167	$915	$1,950	$0
CO	0.29CO	100	Hydro pump	n/a	$0	$0	$75
HI	14.30HI	120	IC Engine	$58	$14	$87	$63
PA	0.31PA	130	Wind	n/a	n/a	n/a	$0
CO	12.33CO	140	IC Engine	$36	$2	$11	$54
NE	0.39NE	500	Cogen	$1,000	$31	$260	$15
NY	0.38NY	500	IC Engine	n/a	n/a	n/a	$15
TX	16.37TX	500	Wind (multi sites)	$0	$0	$0	$0
NY	0.40NY	560	Cogen	n/a	$15	$130	$13
MN	0.41MN	600	Wind	n/a	$0	$0	$0
NH	0.42NH	650	IC Engine (7sites)	$66	n/a	n/a	$12
MD	9.43MD	703	Steam turbine	$125	$18	$152	$11
CO	8.44CO	1000	Diesel IC	$0	n/a	n/a	$8
IL	0.47IL	1200	Cogen	n/a	$0	$0	$6
OH	0.48OH	1200	Cogen	n/a	n/a	n/a	$6
IL	0.49IL	1650	IC Engine	n/a	$4	$33	$5
CO	0.50CO	1925	Cogen	n/a	$0	$0	$4
CO	0.51CO	2000	Diesel IC	n/a	n/a	n/a	$4
KS	0.53KS	4000	IC Engine	$1,750	n/a	n/a	$2
CO	0.55CO	5000	Waste-to-energy	n/a	n/a	n/a	$2
NE	0.56NE	5000	Cogen	n/a	n/a	n/a	$2
NE	0.57NE	8000	Cogen	n/a	$93	$780	$1
NJ	0.59NJ	12,000	Cogen	n/a	n/a	n/a	$1
MS	3.60MS	15,000	Cogen	$129	$3	$22	$1
MN	0.62MN	23,000	Wind	$0	$0	$0	$0
NE	0.63NE	25,000	Cogen	n/a	n/a	n/a	$0
NE	0.65NE	56,000	Waste-to-energy	$0	$8	$65	$0

The table above shows the all the projects included in the Baseline. The "IC Cost Overrun" column shows how much interconnection hardware and labor cost overrun the project had; the next column shows how much cost overrun there is from delay; the "Lost Opportunity Cost" column shows how much revenue the project loses based on a 6.5% return on investment; the following column is the sum of the